Impacts of Coastal Energy Development on New Jersey's Shorefront Recreational Resources and Economy

The New Jersey Department of Environmental Protection

Study Report
Appendix Volume 2

Appendix B: Facility Descriptions

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APPENDICES VOLUMES

Note to Readers

Changes in the descriptors of five of the six tourism regions used in the study **Impacts of Coastal Energy Development on New Jersey's Shorefront Recreational Resources** occurred after final editing of this appendix volume and are not included in it.

Consequently, the reader is asked to substitute the descriptors found in this volume (listed below, left) for those found in the summary report (listed below, right).

Former Version	Final Version
Densely Settled Commuter Suburb	Non-Seasonal Suburban
Northern Shorefront Year-Round and Rural Community	North Shore Non-Seasonal/Rural
Northern Shorefront Seasonal Communities	North Shore Seasonal
Southern Shore Year-Round and Rural Community	South Shore Non-Seasonal/Rural
Southern Shorefront Seasonal Communities	South Shore Seasonal

The tourism region **Resort Gambling** remains unchanged.

APPENDIX B. ENERGY FACILITY DESCRIPTIONS

The magnitude, composition, and timing of the environmental, social, and economic impacts of developing energy facilities in coastal areas are dependent upon the characteristics of the energy facility under consideration. A comprehensive policy planning tool such as the Coastal Tourism Model depends on an understanding and a specification of the functions, purposes, inputs, and impacts of each of the 15 energy facilities being considered within the model. A primary component of the model is therefore the set of 15 energy facility descriptions which contain information that permit model users to begin to proceed along each of the three impact paths. In addition, the descriptions contain information which provide model users with a base of knowledge about the various facilities.

The 15 energy facilities are presented as follows:

- Support Base
- Oil and Natural Gas Pipelines
- Oil Pumping and Gas Compressor Station
- Gas Separation and Dehydration Plant
- Gas Treatment Plant
- Natural Gas Liquids (NGL) Fractionation Plant
- Peak Shaving Facility
- Tank Farm
- Nuclear Power Plant
- Coal-Fired Power Plant
- Cogeneration Facility
- Resource and Energy Recovery Facility
- Electric Transmission Line
- Coal-Handling Terminal
- Offshore Oil Port

The accompanying energy facility descriptions contain the following components:

- Facility Description: Presents the purpose and functions of each facility, along with identification of its major components and design configurations.

- Facility Size/Land Requirements: Notes the range in design capacities or throughputs based on existing technology. Land requirements as a function of size are also given.

- Site Parameters: Lists the features of the physical and man-made environments which each facility requires for cost-effective development at a given site.

- Capital Costs: Capital costs as a function of size are presented in fourth quarter, 1982 dollars.

- Employment Profile: Describes on an annual basis the manual and non-manual components of both the construction and operating labor forces over an eleven-year period for the size of the facility most likely to be developed within the study area.

- Environmental Impacts: Describes the significant environmental impacts by category that would accompany facility construction and operation.

The descriptions utilize some of the information contained within the Coastal Energy Facility Development Potential Study. The descriptions of facility processes and design alternatives are more detailed in the Development Potential Study and interested readers are referred to that document. In addition, the Development Potential Study also contains much more useful data on how the site parameters influence the economics of facility development at a particular site.

Each facility description is accompanied by a Facility Impact Assessment Matrix and an Environmental Change Schedule. Each facility's matrix presents the type and time of occurrence of the on-site activities during the construction and operation phases. Listed for each activity are the direct impacts associated with these activities. The Environmental Change Schedule lists the probability of occurrences of environmental changes that will produce corresponding changes in the tourist visitation patterns. These two components of the model are the primary mechanism for translating facility-related environmental impacts into losses of tourism. The Environmental Change Schedules for each facility are contained in Appendix D. The assumptions and information incorporated into producing both of these items, along with an explanation of the how to interpret the data presented on them, is contained in Impact Path 3, Tourist Response to Environmental Impacts.

Each of the 15 energy facility types noted previously differs in terms of it's probability of ever being located within the study area. This probability for each facility is based on a number of factors, including:

- the need for the facility as a function of changes in the market conditions for the type of energy produced, processed, or handled by it;

- the environmental impacts and associated costs of obtaining the required permits associated with the facility's construction and operation;

- uncertainty o the future regulatory and rate-making climates which affect the probable capital cost and accompanying profitability of a facility;

- the availability of suitable sites within the study area;

- diminishing probability that the Baltimore and Hudson Canyons will prove to have sufficient reserves of oil and natural gas to warrant commercial development; and

- the public's perception of the environmental and public health risks associated with a facility's construction and operation.

Changing market conditions can be the primary determinant in the probability of developing a particular energy facility. Changes in market condition can include the development of competing facilities in other locations so that likelihood for developing such facilities in New Jersey declines. Coal-handling terminals are a prime example, as the large number of projects proposed in other states has diminished the probability of developing a facility in New Jersey. Other changes in market conditions can include changes in the relative price of an energy product, such as oil, with the result that the demand for that product declines.

The difficulty in obtaining the necessary environmental permits can also affect the probability of developing a particular facility. Owners of the Louisiana Offshore Oil Port have noted that the difficulty faced in obtaining the necessary environmental licenses and approvals for their facility make it highly unlikely that a similar facility can be profitably developed elsewhere in the country. In addition, this facility's long-term profitability has declined due to increases in the price of oil, which have resulted in a decrease in demand in the amount of oil imported into this country.

The regulatory uncertainty surrounding the construction of nuclear power plants, along with the long lead times required to construct such capital-intensive facilities, has diminished the probability of constructing these facilities in the near future.

There is a definite lack of suitable sites for some of the energy facilities within the study area. Thus, the likelihood of their development within the study area is quite low. Facilities include tank farms, an offshore oil port (assuming one could be profitably developed) and a coal-handling terminal. The northern section of the study area in Monmouth County is the only part which would have sufficient proximity to navigation channels of proper depth to warrant the expenditure of funds for dredging of sufficient depth to allow coal colliers or tankers access to a coal-handling terminal or a tank farm. From Point Pleasant south, the presence of the heavily developed barrier islands makes the siting of a tank farm or a coal-handling terminal highly unlikely.

Recent cessation of offshore exploration and drilling activity by major oil companies in the Baltimore and Hudson Canyons diminished the probability that commercial development of these areas will ever take place. As a result, the likelihood of developing accompanying ancillary facilities such as support bases, oil or natural gas pipelines, or the three natural gas processing facilities has likewise declined.

As a result of the consideration of these factors, this study estimates the probability of developing each of the 15 energy facility types within the study area over the next 10 to 20 years. Model users should be aware that these probabilities are speculative and aer based on the conditions prevailing in early 1983. Future changes, such as regulatory reform or continuing declines in the price of oil, could significantly affect these probabilities. The probabilities within each group are presented in descending order.

- o HIGH PROBABILITY (50% or better chance of occurrence)
  - Resource and Energy Recovery Facility
  - Coal-Fired Power Plant
  - Electric Transmission Lines
  - Cogeneration

- o MODERATE PROBABILITY (less than 50%, but more than 20%)
  - Support Base
  - Oil and Natural Gas Pipelines
  - Oil Pumping and Gas Compressor Stations
  - Gas Separation and Dehydration Plant
  - Coal-Handling Terminal
  - Peak Shaving Facility

- o LOW PROBABILITY (20% or less)
  - Nuclear Power Plant
  - Gas Treatment Plant
  - NGL Fractionation Plant
  - Tank Farm
  - Offshore Oil Port

Each of the fifteen energy facilities also differs in terms of its dependency on proximity to water. Water dependency is defined as the necessity of utilizing water as a process input (i.e., cooling water for power plants), or the requirement to locate in, or immediately adjacent to, a shorefront site. This dependency translates to the probability of a specific facility type being sited in a shorefront location should it ever be developed within the study area. The need to utilize water as a process input implies that proximity to water is partially a cost-optimization factor. Generally, the closer an energy facility location is to the water supply source, the lower the cost is of obtaining the water. However, the need for water as a process input does not automatically imply a coastal location. Coal-fired and nuclear power plants can be sited at inland locations within the study area if sufficient cooling water supplies are present.

Some energy facilities require a coastal location as a precondition for feasible operation. Such facilities are usually involved in the transfer of a bulk energy commodity from one transportation mode to another. The obvious examples include support bases, tank farms, and coal-handling terminals. If any of these facilities are ever developed within the study area, they will certainly be sited in coastal locations.

Presented below are estimates of each facility type's probability of being located in a shorefront location within the study area. These assessments are specific to the study area being considered in this report. For obvious reasons, an offshore oil port's probability is not considered.

Probability of One: Requires an oceanfront, riverfront or bayfront location adjacent to navigable waters as a precondition for feasible operation:

- o Support Base
- o Tank Farm
- o Coal-Handling Terminal

High Probability: Location in, or as close as possible to, an oceanfront site maximizes the economic efficiency and technical feasibility of an energy facility:

- o Gas Separation and Dehydration Plant
- o Gas Treatment Plant
- o Natural Gas Liquids Fractionation Plant
- o Oil and Natural Gas Pipelines

The above four facilities' probabilities assume the presence of OCS oil and gas development.

Moderate Probability: Proximity to an adequate supply is required; however, the need for waterfront location does not translate into a need for an oceanfront location:

- o Nuclear Power Plant
- o Coal-Fired Power Plant

Low or Zero
Probability: Proximity to a shorefront location or to a water supply source has minor or no influcence on a facility's location:

- o Oil Pumping and Gas Compressor Station
- o Peak Shaving Facility
- o Cogeneration Facility
- o Resource and Energy Recovery Facility
- o Electric Transmission Line

SUPPORT BASES

Facility Description

Support bases link onshore and offshore activities during all phases of Outer Continental Shelf (OCS) oil and gas exploration, development, and production. Materials are assembled and stored at these bases for delivery to offshore drilling rigs and production platforms. There are three types of support bases:

- o bases supporting exploration,
- o bases supporting development and production, and
- o bases supporting platform and pipeline installation.

Bases Supporting Exploration. Temporary support bases are set up during exploratory drilling operations to transfer materials and workers between shore and the offshore drilling rigs. Supply and crew boats and helicopters operate from these bases usually on a 24-hour, 7-day-week basis, shuttling food, water, fuel, drilling mud, cement, drill pipe, casing, and equipment to the rigs and bringing back refuse that cannot be disposed of at sea. Weather conditions and the distance from the offshore drilling locations determine whether helicopters or crew boats are used as the predominant mode of crew transfers.

Bases Supporting Development and Production. Support bases set up during the development or production phases of OCS activities serve basically the same function as temporary support bases--i.e., transferring materials and workers between shore and the offshore facilities on a 24-hour, 7-day-week basis--but on a larger scale. Permanent support bases may be set up by the oil companies involved or by service companies. The land is either purchased or leased on a long-term basis. In some cases a decision is made to simply expand the existing temporary support base. The company operating the base may opt to either bring in other companies such as cement companies, caterers, and other specialist suppliers as tenants, or act as an agent for ordering and distributing supplies.

Bases Supporting Platform and Pipeline Installation. Very similar to the support bases set up during the exploratory phase are the bases set up to support installation of platforms and pipelines for OCS development. Unless a large volume of work over an extended period of time is anticipated, these bases are set up on a short-term basis. Their main requirements are waterfront warehouse space, and service and maintenance facilities for vessels and barges. Road and/or rail access is essential for transporting material into the base.

Facility Size/Land Requirements

Bases supporting exploration have up to 20 berths for supply ships, and they require five acres (ac) per drilling rig being serviced. Pages 3-33 of the Energy Facility Development Potential Study give the vessel requirements during the various offshore phases. Approximately five acres per platform being serviced is the required land area for a supply base supporting development and production or platform and pipe installation. A site with an area of five acres is generally adequate for the installation of a pipeline or up to four platforms. For both platform and pipeline operations a minimum of 200 feet of wharf is required. An additional 200 feet is preferable for each "spread" (about three ships) supporting the platform or pipeline installation operation.

Site Parameters

Siting of support bases involves consideration of several key factors. Properly sited facilities should be areas with the following characteristics:

- adequate flood protection
- fresh water delivery capabilities
- high load bearing capacity soils
- relatively flat topography
- access to railroads and highways
- access to an all-weather harbor with an adequate wharf or pier
- reasonable proximity to offshore activity
- access to and availability of ancillary services

Capital Costs

The total capital cost for a supply base can be estimated using the following equation. Remember that the number of berths required varies with the phase (i.e., exploration, development and production, etc.).

Capital Cost = $1,500,000 (NB)

Where:

NB = number of berths at the support base.

Sources:

John F. McMullen, 1981; Rogers, Golden & Halpern, 1979.

Employment Profiles

The level of construction employment at a support base is low, as the primary activity consists of site preparation (i.e., grading and clearing, construction of docks/wharves and buildings) as opposed to construction of a highly complex processing or production facility.

Construction Profiles:

	temporary service base	permanent service base
Manual	18	34
Non-manual	7	13
Total	25	47

Bases supporting exploration and pipeline/platform installation are considered temporary bases. Bases supporting development and production are permanent service bases. Construction is expected to take six months to one year.

Operating Equipment:

The level of operating employment at a support base varies according to the type of offshore activity being supported. Permanent bases have larger employment levels due to the amounts of materials and services required by the offshore facilities.

	helicopter base	exploration base	development base	prod. base	pipe./plat. instal. base
Manual	15	70	93	56	75
Non-manual	5	5	7	4	10
Total	20	75	100	60	85

Source:

Roy F. Weston, Inc., July 1978. Methodology for Assessing Onshore Impacts for Outer Continental Shelf Oil and Gas Development.

Environmental Impacts

Air Waste Disposal

During construction, heavy machinery will emit hydrocarbons, carbon monoxide and nitrogen oxides during use. Yearly vehicle emission inspection by The New Jersey Department of Motor Vehicles should keep emissions within allowable limits.

Sources of air emissions during the operation of a support base are:

- o evaporation from fuel tanks for the storage of fuel,
- o combustion from machinery and vehicles, and
- o accidental spills, breaks, etc.

The magnitude of air emissions depends on the volume of delivery, storage, and transfer of fuel, supplies, and waste associated with offshore oil and gas operations.

Support bases involved in the storage and transfer of dry, pumped cement and mud are major sources of dust emissions. Large dust clouds can form as a result of accidental spillage or hose blowouts.

Recreation and tourism impacts, as a result of support base air waste disposal, are anticipated to be minimal. Dust clouds, because of their high visibility, cause the most serious potential impact.

Water Use/Water Discharge

Support bases commonly have three sources of wastewater, namely sewage, bilge water, and ballast water. Sewage wastes generated by a support base are discharged into municipal sewage treatment systems. The discharge of sewage wastes from support or crew boats is controlled by Coast Guard-approved sanitary waste devices. Any system that cannot meet the regulated standards would have to utilize holding tanks for sewage.

Bilge and ballast water are generated by work boats utilizing the support base. Bilge water could contain petroleum and heavy metals that would be toxic to marine organisms if discharged into coastal waters. Ballast water could contain similar contaminants and fecal bacteria that would have a high biological oxygen demand. As a result, the Coast Guard actively enforces regulations that require bilge and waste water discharges to be made to onshore receptacles or to be released greater than 50 miles to the coast.

Impacts to recreation and tourism will be minimal with proper adherence to regulations. Impacts to biota and the aesthetic quality of an area could result because of improper waste water disposal and in turn adversely impact tourism and recreation.

Solid Waste

During OCS drilling operations, drilling muds and drill cuttings are used to aid the process. Drilling muds are chemical mixtures which are circulated through a well bore during drilling, while drill cuttings are those rock particles displaced during the drilling of a well. The primary functions of drilling muds are to cool and lubricate one drill bit and drill pipe; transport drill cuttings to the surface; and provide hydrostatic pressure to prevent blowouts. (U.S. Dept. of the Interior, 1981)

The discharge of drilling muds and cuttings is regulated by NJPDES permit requirements. Although the discharge at sea of oil-based muds is prohibited, substantial quantities of conventionally-used muds can be discharged at sea. The large quantities of oil-based wastes must be returned to the shore through the service base.

Because drilling wastes often contain hazardous materials, such as oils, acids, or heavy metals, they must be disposed of in secure landfills where there is no danger of groundwater contamination, surface water runoff, or evaporation (NERBC, 1978).

Solid waste generated by the support base operation can be incinerated, disposed of by landfilling, or disposed of with sewage. Little adverse environmental impact is anticipated if these materials are disposed of in accordance with existing regulations. (NERBC, 1978).

Impacts to tourism and recreation are anticipated to be minimal with normal operation. However, as with any hazardous waste, the potential exists for groundwater contamination and the subsequent diminished usability of an area.

Noise

Because a support base is in operation 24 hours a day, noise is generated continually. Sources of noise from a support base include pneumatic power tools, air compressors, pumps, compressed air machinery for painting and cleaning, and industrial trucks and cranes.

Impacts to tourism and recreation are dependent upon the size of the support base, proximity to recreation area and the existence of a buffer zone. In general, a noticeable increase in the ambient noise level will detract from the quality of a recreation area, and may affect use of the area.

Aesthetic Impact

The aesthetic impact of a support base, in any of the three phases, will depend primarily upon the area in which the base is located. In an industrial port, a support base would have minimal impact. In an undeveloped port a 24-hour lighted storage facility with heavy machinery in continual operation and trucks, trains and boats constantly arriving and leaving, would have a much greater aesthetic impact.

Impacts to tourism and recreation would be dependent upon the size of the support base, the amount of activity generated, and the existence of a buffer zone. Because of the essentially non-residential character of the study area, the aesthetic impact of a support base is anticipated to be noticeable.

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PIPELINES

Facility Description

The pipelines considered in this study include oil and natural gas pipelines on land, and offshore to the 3-mile (mi) limit.

Oil pipelines are generally built by the companies producing oil, either on an individual or cooperative basis. Natural gas is usually sold on the platform to a gas transmission company, which builds the pipeline to transport the gas from the platform to its transmission line.

Offshore Pipelines. A pipeline system servicing offshore activity, whether for oil or gas, may consist of a pressure source (if well pressure is not sufficient), gathering lines, a main pipeline, intermediate pressure booster stations, a landfall, and an onshore destination. When several companies are operating in the same general area, they are required by Federal regulations to build a common carrier pipeline that transports their combined products. Careful metering of the throughput at both ends ensures that each company receives its share.

Usually the marine pipeline is routed to the nearest point of land because of the expense of building marine pipelines (approximately 1.5 times the cost of building onshore pipelines). However, other factors such as earthquake fault zones, bathymetry and underwater obstructions (i.e., pipelines or cables), excessive depths, bottom currents, shifting sand dunes, environmental sensitivity, marine activity in the area, and proximity to existing or potential onshore facility sites may necessitate a longer route.

Pipeline Landfall. The landfall is the section between the last points where lay-barges and conventional onland pipelaying equipment can operate. The selection of a landfall site involves minimizing the length of the more costly marine section, considering the onland pipeline route, and accommodating the siting of associated onshore facilities.

If incoming oil is to be transshipped by tanker, the landfall must be located near a site suitable for a tanker terminal and tank farm. If the oil is to continue by onland pipe to a refinery, a pumping station may be the only facility associated with the landfall.

The landfall for a gas pipeline is usually located near an existing or potential gas separation/dehydration plant or gas treatment plant. These facilities are owned by the producer, who retains the rights to the liquefiable hydrocarbons contained in the gas stream and recovered in the separation process.

Beach-upland areas (referred to as the headlands in New Jersey) often include a bluff or steppe upgrade, composed of rock or compacted sediment, adjacent to a narrow, sometimes nonexistent beach. Construction in these areas tends to be very difficult and expensive due to high erosion rates, corresponding steep offshore slope, and lack of sufficient sediment for burial. Techniques such as sheet-piled cofferdams and explosives would be utilized in conjunction with techniques employed with a landfall in a barrier island beach-dune system.

Onshore Pipeline. An onland pipeline system consists of a main pipeline, valves, and pressure booster stations. It may also include branch pipelines, loops, multiple main lines, and/or meter stations.

Onshore pipelines (oil or gas) may be very inconspicuous after completion, particularly where it does not pass through a wooded area. A pipeline right of way (ROW), either purchased in fee or as an easement, is required for construction of oil and gas pipelines. Revegetation can be hastened by separation of topsoil and subsoil during excavation. It is general practice and the expressed use policy for pipelines and associated facilities as stated in the New Jersey State Coastal Management Program to locate pipeline ROW corridors in or parallel to existing ROWs of highways, power transmission lines, railroads, other pipelines, or similar facilities.

Factors influencing pipeline route selection include topography, geology and soils, type and number of crossings (water bodies, roads, and railroads), and land use.

When the pipeline crosses bodies of water, roads, or railroads, special pipelaying techniques must be used. These involve additional construction costs. Stream crossings may utilize one or more of the following methods: bottom pull, floating bridge, floating barge, and directionally controlled horizontal drilling. Road and railroad crossings may also be accomplished by several methods, including open cutting of roadway (unpaved or lightly traveled), and boring under roadways (heavily traveled roads or railroads).

Facility Size/Land Requirements

The diameter of transmission pipelines, whether for oil or gas, ranges from 6 to 48 inches. Throughput capacities range from .5 to 10,000 million cubic feet/day (MMcfd) for gas (at 1,100 pounds per square inch maximum) and 5 to 2,000 thousand barrels/day (Mbpd) for oil (at 1,440 pounds per square inch maximum). Onland ROWs vary from 50 to 100 feet in width.

Onshore oil pipelines and gas pipelines require 6 to 12 acres per mile. The acreage requirement varies with the pipeline's capacity and corresponding diameter.

Site Parameters

Because of their high cost, the shortest route is often the most important criterion for locating pipelines. Marine pipeline routes should avoid anchorage areas, existing underwater objects, active faults, rock out-crops, mud slide areas, and areas which are environmentally sensitive. The shore approach should be gently sloping with sufficient depth of sand or shingle to give not less than ten feet of cover over the pipeline at the low water mark and seven feet of cover at a depth of 50 feet. Areas subject to seabed shifting or strong tidal flows should be avoided. Erosion caused by shifting could undermine pipeline support, placing additional stress on the pipeline and possibly causing it to fail.

Criteria for a landfall site include a flat approach or a reasonably gentle transition from marine to land environment. Proximity to acreage for a pre-existing compressor and pumping station or tank farm may also be included in the site parameter.

On-land pipelines also attempt to find the shortest route. However, pipelines should be routed around environmentally sensitive and densely populated areas. The lack of availability of land, and its high cost in developed areas weigh against pipeline ROWs in these areas. Pipeline routes should minimize the number of special crossings (i.e., roads, rivers) and areas of high relief as construction costs are higher in these areas.

Capital Costs

The cost of constructing an offshore oil or gas pipeline is approximated as follows:
Capital Cost = 277,000 (1.0356^D)L

The cost of constructing an onshore pipeline is approximately:

Capital Cost = 77,000 (1.0705^D)L

Where:

D = the pipeline diameter in inches

L = length of the pipeline route in miles.

The total cost for a 36" onshore pipeline extending 100 miles would be:

Capital Cost = (77,000 \$/inch of diameter/mile)($1.0356^{36\text{inches}}$)(100 miles) = \$27,127,153

Employment Profile

Employment figures for construction of onshore and offshore pipelines to some degree vary with the length of the pipeline. Construction crews will also vary depending on pipeline diameter, topography, and bathymetry. As longer pipelines are constructed, instead of having one construction crew work for a longer period, companies often use several crews to construct different segments of the line simultaneously.

In order to present a complete picture, sets of data are listed below for both onshore and offshore pipelines. The 5-mile offshore pipeline would take six months to install, while the 100-mile offshore pipeline would take one year. The two onshore pipelines would take one year to construct.

Offshore Construction Employment:

	5-Mile Pipeline	100-Mile Pipeline
Manual	246	303
Non-manual	26	25
Total	272	328

Onshore Construction Employment:

	150-Mile Pipeline	1,500-Mile Pipeline
Manual	160	1,090
Non-manual	22	120
Total	182	1,210

Construction crews for pipelines usually include the following types of workers: welders, oilers, mechanics, electricians, pipefitters, plumbers, laborers. The 1,500-mile pipeline consists of three groups of workers and equipment (known as "spreads") working simultaneously, averaging 400 workers per spread.

Operational employment for pipelines consists of maintenance crews that make regularly scheduled, periodic inspections of the pipeline to check for leaks or damage. In addition, work crews regularly maintain the ROW by clearing vegetation, etc.

Sources:
BLM/Alaska OCS Office, 1979; Northern Tier Pipeline Company; Roy F. Weston Inc., 1978; Santa Fe International Corp., 1979.

Environmental Impact

Spill/Accidental Discharge

Spills of petroleum onto land or into fresh or salt water resulting from breaks in pipelines are the potentially greatest impacts from operational pipelines. Causes of pipeline breakage can include any of the following: external corrosion, damage from equipment (anchors, fishing nets), defective pipeline seams, internal corrosion, and improper operation by personnel. Although quality control measures and technological advances have increased in recent years, the potential for an oil spill still remains.

Clean-up efforts involve the following techniques:

- burning the oil floating on the water's surface,
- utilizing sinking agents,
- utilizing dispersants, and
- skimming and absorbing the oil.

Of the clean-up efforts available, only the last option--skimming and absorbing the oil--is widely used. The remaining options all have possible additional polluting effects.

The operation of marine pipelines may also involve chronic low level leaks. The petroleum leaks dissolve into the surrounding water and terrain during normal operation.

Biological resources are adversely affected by an oil spill because of the petroleum's toxicity and/or coating properties. The extent of the impact is the subject of a great deal of research. If an oil spill reaches a recreational boating, swimming and/or fishing area, the aesthetic impact is obvious. Impacts to tourism and recreation activities can be expected, but the degree of impact is influenced by media coverage, clean-up efforts, and the volume of the spill.

Solid Waste

Normally, operating pipelines do not generate solid waste. However, solid waste is associated with pipelines in the event of an oil spill. Absorbants are commonly used to "soak up" the oil, and any non-recoverable oil and oily waste must be disposed of in a hazardous waste landfill.

Aesthetic Impact

Depending upon site restoration practices at the time of construction, pipelines may not be noticeable. However, where the vegetation is not as easily restored the impact could be more severe. Aesthetic impacts can be particularly noticeable where pipeline ROWs pass through forested areas, resulting in highly visible linear gashes standing in contrast to the surrounding natural scenery. Impacts related to pipelines may be less important than aesthetic impacts associated with other onshore energy facilities.

Ecological Impacts Due to Construction

The Department of the Interior requires the burial of pipelines in water less than 200 feet deep. The trenching method used to bury the pipeline removes sediments under the pipeline through the use of high pressure jets. As a result, increased turbidity may affect benthic organisms. In shallow waters, contour restoration is more rapid than in deeper waters. In bedrock areas, the necessary blasting may kill marine animals in the blasting area.

At the landfall site, construction impacts may be greater because of the critical areas at the marine--land interface. Special construction procedures are necessary to protect dunes, barrier islands, marshes and estuaries.

Onshore pipeline construction activities disrupt soil, vegetation, and animal habitats. The impact depends on the characteristics of the site. Where pipelines cross rivers and streams the impact potential is greater than for flat, upland sites. Long-term modifications in water quality, water table levels, and vegetation could result if water-holding properties of soil layers in wetlands were not restored to pre-construction conditions. Tourist-related impacts would be largely confined to the construction phase.

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OIL PUMPING AND GAS COMPRESSOR STATIONS

Facility Description

These facilities are required to transport the oil or natural gas through the pipeline, and to maintain desired operating pressure in the pipeline. A typical gas compressor station consists of one or more compressors, depending upon the volume of gas in the pipeline, and the temperature and pressure to which the incoming gas must be compressed. Station size in terms of horsepower (HP) requirements generally increases with higher throughput capacity, higher operating pressures, and/or greater transmission distances between stations. Pumping stations for crude oil pipelines usually consist of one of more pumps linked together in series that send the crude oil from one station (or other departure point such as a tank farm) to the next pumping station or other destination (e.g., a refinery). The number of pumps required, and the HP of each one is dependent upon a number of factors, including the daily throughput capacity in thousands of barrels per day, the type of crude (i.e., different crudes have varying specific gravities), topography, and the maximum operating pressure of the pipeline.

Facility Size/Land Requirements

Oil pumping and gas compressor stations may have ten or more compressors or pumps with total station energy requirements approaching 40,000 HP. Throughput capacities for oil pumping stations can range as high as 2 million barrels/day (MMbpd) and for gas compressor stations as high as 2,000 MMcfd. Gas compressor stations generally have total energy requirements between 2,000 and 10,000 HP, while oil pumping stations have total station energy requirements of between 5,000 and 15,000 HP.

An oil pumping station may require as much as 40 ac of land and includes storage tanks, an office, and the pumping station itself. Onshore gas compressor stations, fueled by natural gas or refinery gas, require from 10 to 25 ac of land located along the pipeline corridor. Land requirements would increase only minimally as a function of throughput capacity. This is because additional pumps or compressors require little additional land area.

Site Parameters

Oil pumping or gas compressor station locations are usually dictated by the operating conditions (i.e., temperature and pressure of the pipeline, as well as physical and chemical characteristics of the substance being transported). Locations for pumping or compressor stations should be flat, with well drained soils, and not be subject to flooding (coastal or riverine) or coastal erosion. Sites should be large enough to have adequate land for a buffer zone, and should be located in rural or undeveloped areas. Oil pumping stations often need to be located near existing electric transmission lines in order to obtain energy to drive the pumps. In cases such as the Trans-Alaska Pipeline, small on-site refineries called topping plants are used to produce a kerosene-like fuel from crude oil extracted from the pipeline which is then used to drive the compressors. They do not, therefore, require proximity to electric transmission lines.

Capital Costs

Oil Pipeline Pumping Station - Onshore:

Capital Cost = (470$/hp)(HP)

Where:

HP = the total pumping station horsepower

The equation assumes the use of centrifugal pumps.

Source:
United States Department of the Interior, Bureau of Land Management, 1979.

Natural Gas Compressor Stations - Onshore:

Capital Cost = $113,000 + (415$/hp)(HP)
The equation assumes the use of centrifugal compressors.

Source:

Federal Energy Regulatory Commission, 1980, Oil & Gas Journal, Annual "Pipeline Economics" issues from 1978-82.

Employment Profile

The labor force required to construct and operate both oil pumping and gas compressor stations are presented as follows:

Construction:

Oil Pumping Station (500 Mbpd)		Gas Compressor Station (2,000 MMcfd)	
Manual	27	Manual	48
Non-manual	7	Non-manual	6
Total	34	Total	54

Oil pumping and gas compressor stations generally take from four to six months to construct.

Operation:

Oil Pumping Station (500 Mbpd)		Gas Compressor Station (2,000 MMcfd)	
Manual	6	Manual	14
Non-manual	1	Non-manual	2
Total	7	Total	16

The number of operating personnel at an oil pumping station increases gradually up to 1,000 Mbpd and then levels off at ten operating employees, one non-manual and nine manual workers.

The number of operating personnel at a gas compressor rises slowly from lower production rates but levels off at 2,000 MMcfd. Smaller pumping and compressor stations are almost totally automated, and require only periodic visits by operating personnel.

Sources:
Roy F. Weston, Inc., 1978.; U.S. Department of the Interior, Bureau of Land Management, 1979.

Environmental Impact

Air Waste Disposal

During the operational phase, air emissions will be generated from compressors and pumping stations. The pumps and compressors are fueled by either natural gas or refinery gas (i.e., fuel produced by small on-site refinery-like facilities which obtain fuel from crude oil extracted from the pipeline). The major emissions are sulfur oxides and hydrocarbons. Nitrogen oxides are also emitted from gas compressors and are a direct function of the load on the compressor engine.

The overall impact of removal pumping and compressor station operations on ambient air quality appears to be minimal. This is because the amount of emissions generated by pumping or compressor stations would not be significant enough to result in decreases in local ambient air quality conditions. Impacts on recreation and tourism are anticipated to be minimal.

Spill/Accidental Discharge

For a complete discussion of oil spills related to pipeline and pumping/compressor station operation, refer to the Spill/Accidental Discharge Section in the Pipeline facility write-up.

Noise

Compressors generate the most noise during operation, approximately 92 to 100 "A" weighted decibels dB(A) at the source. The pumps and compressors run day and night so their presence could significantly increase nighttime ambient sound levels in adjacent areas. Silencers built into the compressors can lower the noise level. Approximately once a year, venting of high pressure gas in a pipeline and at the compressor station occurs, lasting approximately 45 minutes on the pipeline and five minutes at the station. Uncontrolled noise levels peak at 140 dB(A), but silencers can lower the level to almost half.

With proper controls, sound levels can be controlled and buffered, resulting in little or no impact on tourism and recreation. Use of improper controls can, however, reduce the quality of an area and may impact the number of participants using recreation/tourist areas.

References

Federal Energy Regulatory Commission, 1980. Cost of Pipeline and Compressor Station Under Non-Budget Pipeline Certificate Authorization for the Years 1976 through 1979, Washington, D.C.

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GAS SEPARATION AND DEHYDRATION PLANT

Facility Description

Gas separation and dehydration involves separating the gas, oil, and free water components of the well stream into separate components, and dehydrating the liberated gas to remove water vapor. Free natural gas is obtained from the well stream by either a two-phase process which separates gas from the rest of the well stream or by a three-phase process which results in separate gas, oil, and free water components. Heavy liquid hydrocarbons are settled out in one or a series of separation vessels, each at successively lower pressures. (These recovered liquids are subsequently processed "downstream.")

The liberated gas passes through a valve at the phase interface and on to the dehydration process. Dehydration, by removing water vapor that remains in the gas stream after separation, prevents the build-up of solid hydrates along the pipeline and minimizes corrosion by acid gases often present in the gas stream. The most common dehydration process involves the use of absorbers containing triethylene glycol, which removes the water vapor from the gas as it passes through the dehydrator.

Onshore separation/dehydration facilities are generally located as close as possible to the pipeline landfall either as a separate facility, or together with a marine terminal, an NGL fractionation plant, or a gas treatment plant. A location at the pipeline landfall is desired so as to minimize the higher costs incurred in transporting the unprocessed gas, as well as to enable pipeline-ready gas to be available for sale as soon as possible. Gas separation/dehydration plants are generally owned and operated by gas pipeline companies or purchasers of the gas (i.e., utilities).

Facility Size/Land Requirements

There are no standard sizes or process configurations for a gas separation/dehydration plant as each one is individually designed around a particular gas stream's chemical composition and flow. Gas separation/dehydration plants have throughput capacities ranging in size from 20 MMcfd to 2,000 MMcfd. The smaller gas separation/dehydration facilities are portable plants mounted on skids, while the larger plants (above 100

MMcfd) are permanent structures. Most permanent gas separation/dehydration plants have throughput capacities of between 200 and 500 MMcfd.

The amount of land required for a gas separation/dehydration plant is related, but not directly proportional, to the plant's throughput capacity. Two-thirds of the total land area is required for the facility with one-third for buffering. The following equation can be used to estimate the land area required for a separation/dehydration plant:

LAND = .03(CAP) + 20

Where:

CAP = throughput capacity in MMcfd

LAND = total land area in acres

Site Parameters

Coastal sites are preferred which are immediately adjacent to pipeline landfalls and easily accessible by highways and/or a railroad siding. Locations should not be in areas subject to periodic coastal flooding or erosion. Potential sites should be level, contain well-drained soils, and be of sufficient size to provide adequate buffering.

Capital Costs

The following equation may be used to estimate the capital cost of a gas separation and dehydration plant:

Capital Cost = $15,500,000 + (33,000$/MMcfd)(V)

Where:

V = Daily throughput in MMcfd.

As a comparison, a 200 MMcfd gas separation and dehydration facility that also includes gas treatment, gas processing (i.e., removal of natural gas liquids), and fractionation is estimated to cost between $50 - $80 million (Dr. V. Mohr, Lotepro, Inc., 1982).

Employment Profile

The construction duration and construction labor force requirements of a gas 200 MMcfd separation and dehydration plant are presented below.

	Year 1	Year 2 (6 months)
Manual	130	300
Non-manual	15	35
Total	145	335

The peak labor force for the above facility is estimated to be approximately 500 workers. As a comparison, the 200 MMcfd gas separation and dehydration plant, that also includes gas processing, treatment, and fractionation components, would have a peak labor force of approximately 1,500 workers on-site for a short period of time (3-4 months) (V. Mohr, Lotepro, Inc., 1982).

The operating labor force for a 200 MMcfd gas separation and dehydration plant is estimated at 15-18 persons (New Jersey Department of Energy, 1981).

Environmental Impacts

Air Waste Disposal. There will be some occasional flaring of small amounts of natural gas at a separation/dehydration plant, along with releases into the atmosphere of water vapor from the glycol reboilers. However, no major air pollutants will be emitted from the facility, and the intermittent releases noted above would not be significant enough to have any perceivable effect on local air quality such that tourist activity would decline.

Liquid Waste. The major source of liquid waste would be the glycol compounds used in the dehydration unit that serve as liquid dessicants (a dessicant is a solid or liquid having an affinity for water; in the above case gas is bubbled upward through a glycol solution, which removes the water vapor from the gas). If properly disposed, glycol compounds should not pose any significant health or environmental risk.

Water Use/Water Discharge. Gas separation/dehydration plants do not consume water for processing or cooling. However, the process of separation results in the removal of water from the gas stream, which has a high salt content. This water is often stored on-site in tanks before removal to an off-site disposal location. In other cases, the salt wastewater is disposed of through deep well injection. The disposal of the wastewater should not result in any significant impact on recreational activities if it is disposed of in a proper manner.

Spill/Accidental Discharge. A number of liquids that are either used or produced as a result of the separation/dehydration of gas could cause environmental damage if released because of an accidental spill or discharge. These include the natural gas liquids and salt water generated by the separation process, and the glycols used in the dehydration process. The accidental release of these liquids from oceanfront gas separation/dehydration plants could have adverse impacts on the surrounding area's environment, thus potentially reducing its attractiveness as a recreational location. The magnitude and duration of any adverse impacts would be a function of the facility's throughput capacity.

Noise

Apart from the heavy equipment needed during the construction of a gas separation/dehydration plant, the major impact on ambient sound levels would be from the operation of compressors. They would only be required in instances where the pressure from offshore wells is not enough to drive the gas to the nearest interstate gas pipeline. Use of a compressor with proper on-site soundproofing would not increase ambient sound levels at 300 meters by more than five decibels (NJDOE, 1981). When required, compressors would operate continuously, having a substantial effect on ambient, nighttime sound levels. This could have adverse, localized effects on tourism in areas whose attractiveness depends in part on their perception as tranquil locations offering an opportunity for rest and relaxation.

Aesthetics

The most visible structures of a gas separation/dehydration plant would be approximately 40-50 feet high. Thus, any adverse aesthetic impacts would be confined to a small area. However, the facility's continuous operation and accompanying evening lighting, along with the intermittent flaring of gas, could constitute a more adverse, localized aesthetic effect than the presence of the structures. In some instances a communication tower, ranging up to 500 feet in length, could be required. A structure this size would be clearly visible for quite a distance in the flat, coastal locations that comprise the study area. The other adverse tourism-related aesthetic impact would be where the facility's presence is visually incompatible with an adjacent scenic, natural, or coastal location.

References

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GAS TREATMENT PLANT

Facility Description

Natural gas often contains acid gases, primarily hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Natural gas streams with high concentrations of either H_2S or CO_2 are referred to as "sour" gas, and the process of removing acid gases is known as "sweetening". A gas treatment plant is the facility used for removing acid gases from the natural gas stream.

Hydrogen sulfide must be removed from the gas stream because it is a toxic, poisonous gas, and because, in the presence of water vapor, it is extremely corrosive. Its presence in the gas stream decreases the useful life of pipe, valves, and pressure vessels; and increases operating and maintenance (O & M) costs for the pipeline. In addition, it is very expensive to provide specially coated pipe and handling facilities capable of resisting the corrosive effects of the gas when it is being sent over long distances. Removal of carbon dioxide is desired because it is also corrosive when water is present in the gas stream, and because carbon dioxide is conducive to the formation of hydrates, whose formation can lessen flow rates and impair the functioning of the pipeline.

As with a gas separation and dehydration plant, a gas treatment plant is designed specifically for the chemical composition of the gas stream it will be treating. Some of the major processes used in a gas treatment plant include iron-sponge sweetening, absorption with an amine solution, and a molecular sieve.

Facility Size/Land Requirements

Gas treatment plants can range in size from 2 to 2,000 MMcfd in terms of throughput capacity. Typical facility sizes range between 200 and 500 MMcfd.

Approximately 50-75 acres per 1,000 MMcfd of daily throughput capacity is required, with approximately one-third of the total site required for buffering.

A sulfur recovery plant often accompanies the construction of a gas treatment plant in instances where the natural gas stream has a high concentration of hydrogen sulfide. The sulfur recovery plant converts the H_2S into elemental sulfur, which can then be sold for other industrial process uses. The most common sulfur recovery process is the Claus process, in which H_2S is first oxidized to remove most of the sulfur, with the rest being removed in catalytic converters. Preliminary indications are that natural gas found off New Jersey would not likely require the use of a sulfur recovery plant, as it is fairly "sweet" gas.

Site Parameters

On-shore gas treatment plants should be located as close as possible to the pipeline landfall. This minimizes the extra costs that result from the corrosive effects of sour gas, and the extra energy costs incurred in pumping the sour gas constituents.

A gas treatment plant is often co-located with a gas separation/dehydration plant at a shorefront location. A site should be level, with well-drained soils, and not situated in areas subject to coastal flooding or areas with seasonably high water levels. Finally, sites should be accessible by highways and railroads.

Capital Costs

The capital cost of a gas treatment plant varies widely based on the volume and chemical composition of the gas stream. In addition, there are economies of scale that are gained when a gas treatment plant is constructed at the same location as any of the other natural gas facilities. Smaller units, treating less than 50 MMcfd, are often mounted on skids for temporary installation, while larger treatment facilities are permanent structures.

The capital cost of a gas treatment plant may be estimated using the following equation:

$$\text{Capital Cost} = (12{,}700{,}000\$/\text{MMcfd})\,(1.0034^{V})$$

Where:

V = throughput capacity in MMcfd

This equation applies to units with capacities of 30 MMcfd or greater.

Sources:
Ford, Bacon & Davis, Dallas, Texas, 1982; Pacific Offshore Pipeline Co., 1982; Proser Co., Houston, 1982; Superior Oil Company, 1982.

Employment Profile

The construction labor force requirements for a 60 MMcfd and a 200 MMcfd plant are listed as follows:

	Year 1		Year 2 (6 months)	
	60 MMcfd	200 MMcfd	60 MMcfd	200 MMcfd
Manual	150	250	225	350
Non-manual	12	15	20	30
Total	162	265	245	380

The operating labor force for a gas treatment plant increases only marginally for plant sizes above 50 MMcfd due to the use of automated control systems. Operating labor force for a gas treatment plant would be approximately 20 - 25 persons.

Sources:
Pacific Offhore Pipeline Co., 1982; Superior Oil Co., 1982.

Environmental Impacts

Air Waste Disposal

Construction-related pollutant emissions would depend on the type and amount of heavy equipment utilized, however, as noted previously, New Jersey's vehicle emission standards should minimize the impacts of construction activities on ambient air quality.

During operation, gas treatment plants produce hydrogen sulfide, which if produced in amounts too small to economically justify sulfur recovery, may be flare-vented or incinerated if permitted by local air quality regulations. The pollutants released to the atmosphere include sulfur dioxide (SO_2), nitrogen oxides (NO_x), and smaller amounts of hydrocarbons. In cases where a sulfur recovery plant accompanies a gas treatment plant, significant amounts of sulfur dioxide are produced.

If gas treatment plants, without accompanying sulfur recovery plants are con structed in New Jersey (as seems likely given the relatively "sweet" gas off New Jersey), the impact of air emissions on ambient air quality should be minimal. As a comparison, the 2,300 MMcfd gas treatment plant (without sulfur recovery) proposed for Prudhoe Bay, a class II area in terms of air quality, was projected not to result in any significant deterioration of ambient air quality (FERC, 1980). The corresponding effects on tourism should likewise be minimal.

Water Use/Water Discharge

Wastewater is produced as part of the gas treatment process, however, in most sweetening processes, little of this is process water. The wastewater discharges can, for the most part, be accommodated by the local municipal sewer system, though some pre-treatment may be required for cooling water and process water. The environmental impacts and the accompanying effects on tourism should be negligible.

Spill/Accidental Discharge

A malfunction at a gas treatment plant could result in spillage where sweetening processes use liquid chemicals (i.e., amines) or liquid solvents as absorbents. The magnitude and direction of the environmental effects accompanying any spills would vary widely according to site-specific conditions and the size of the plant.

Noise

The operation of a gas treatment plant results in noise being produced by the continuous operation of compressors, boilers, scrubbers, and flarestacks. The location of a gas treatment plant in a commercially developed coastal location (with an ambient sound level (LEQ) in the vicinity of 50-55 decibels), could result in a significant increase in ambient sound levels in the vicinity of the plant. However, as with a separation/dehydration plant, if the site is properly buffered and proper sound attenuation measures are adopted, sound levels would likely not increase by more than five decibels above ambient levels at 300 meters (NJDOE, 1981).

The presence of a gas treatment plant in an area prized for its rural ambience and solitude (i.e., with an LEQ of between 40 and 50 decibels) could adversely impact tourism activities in the immediate area. However, this impact would be very localized, extending no more than a quarter of a mile from the site.

Aesthetics

Gas treatment plants' primary adverse aesthetic impacts would come from the flaring of natural gas and the presence of lights from 24-hour operation. A gas treatment facility's structures would be relatively low (under 50 feet), and would therefore not be visible over a substantial area. As with other facilities, the siting of a gas treatment plant in a scenic natural or coastal location would be incompatible with the existing aesthetic environment. The incompatibility of the structure itself vis-a-vis the surrounding environment, as well as the flaring and lighting effects, could decrease a location's attractiveness as an area for tourism activities.

Odor

Odors are produced by the incomplete combustion and occasional venting and flaring of hydrogen sulfide. The unpleasant odor associated with this gas could certainly have a significant adverse effect on tourism activities occurring in the surrounding area. The magnitude of the effect would depend on the frequency of the releases and prevailing atmospheric conditions around the site.

References

Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation, July 1980. Final Environmental Impact Statement: Prudhoe Bay Project, Washington, D.C.

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NATURAL GAS LIQUIDS (NGL) FRACTIONATION PLANT

Facility Description

In addition to oil, water, and "sour" (i.e., hydrogen sulfide and carbon dioxide) components, liquefiable hydrocarbons such as ethane, butane, and propane may also be present in a natural gas stream. If the gas stream is rich in these natural gas liquids, it may be economically attractive to separate the bulk liquids content into these individual components. A gas processing plant is first used for removing liquefiable hydrocarbons from the gas stream. A natural gas liquids fractionation plant then separates the liquefiable hydrocarbons into their constituent components. Both the gas processing plant and the fractionation plant are located "downstream" from a gas treatment plant.

NGL relies on the different vaporization temperatures of the products. The process is performed in a series of fractionating towers. The lighter, more volatile products are vaporized first, condensed, and collected, while the remaining liquid is fed to the next tower, where the process is repeated for the heavier products. The major constituents usually separated out by a fractionation facility include ethane, propane, butane, and pentane. The individual fractionating towers are named for the product they remove, and are thus called a dethanizer, a depropanizer, a debutanizer, etc. The specific design of a fractionation plant depends on throughput capacity, the relative abundance of desired products in the bulk liquid, and the desired recovery rate of those products.

An NGL fractionation plant would be located at a gas separation/dehydration plant, or at a gas-processing plant only if the volume of NGL recovered from a single facility were large enough to economically justify the operation of a fractionation plant. In most other cases, a fractionation plant would be centrally located so as to receive the NGL produced by a number of gas separation/dehydration or gas processing plants. In New Jersey it is likely that NGL would be collected at individual locations and shipped by tanker truck to a centrally located fractionation plant.

Facility Size/Land Requirements

Fractionation plants may be designed for any volume. Typical throughput capacities of these facilities range from 5 to 50 Mbpd of natural gas liquids.

As with the other natural gas-related facilities, the land required for an NGL fractionation plant is related, but not directly proportional, to the plant's throughput capacity. The following equation can be used to estimate land requirements:

$$LAND = .03(CAP) + 30$$

Where:

LAND = plant area in acres
CAP = plant daily processing capacity in thousands of barrels (Mbpd)

Site Parameters

Fractionation plants have the same general siting requirements as gas separation/dehydration and gas treatment plants. The one exception is that they do not have to be located close to pipeline landfalls or close to the interstate gas pipelines.

Capital Costs

The capital costs of a 10,000 barrel/day gas liquids fractionation plant are estimated as follows:

Capital Cost = (400$/barrel per day)(BPD) + $4,000,000

Where:

BPD = barrels of condensate processed per day

This assumes the fractionation of the condensate into propane, butane, and pentane.

Sources:
Ford, Bacon & Davis, 1982; Pervin and Gurtz, 1981.

Employment Profile

The employment required to construct and operate a natural gas liquids fractionation plant is small in comparison with most of the other natural-gas-related energy facilities. This is due to the small size of the facility.

The construction labor force consists of:

	Year 1 (6 months)
Manual	98
Non-manual	6
Total	104

The operating labor force will be small for two reasons. First, fractionation facilities will generally be located at gas processing plants, and the labor force required to operate these facilities would also have the responsibility of overseeing the fractionation facility. Second, state-of-the-art fractionation facilities employ highly automated control systems and would require a minimal amount of operating labor. It is estimated that no more than five persons (all manual) would be required to operate a gas liquids fractionation plant.

Environmental Impacts

Air Waste Disposal

As with other energy facilities, there will be emissions from vehicles and heavy equipment utilized on-site during the construction of an NGL fractionation plant. Given the relatively short construction period for this facility, and the existing vehicle emission control program in New Jersey, the impacts during the construction phase should be minimal. During operation an NGL fractionation plant will release small amounts of hydrocarbons from valves and fittings during the fractionation process. In addition, combustion-related emissions from the operation of boilers and compressors will also occur. The environmental impacts accompanying these emissions would be minimal, and would not be expected to have discernible effects on tourism.

Water Use/Water Discharge

The major consumptive use of water in an NGL fractionation plant is for cooling and condesning each constituent as it leaves each fractionator. This water usually contains chemicals which prevent scaling and fouling in the condenser and cooling system, and this water would likely have to be pre-treated on-site before being sent to a local municipal wastewater treatment system. Process requirements would be of a lesser degree than cooling water requirements, but would also require pre-treatment before being released to the local wastewater treatment system. The volume of water required by an NGL fractionation plant would not be large enough to have any significant effect on local water supplies (i.e., as compared to the cooling water requirements of an electric generating plant). Similarly, the environmental effects accompanying the wastewater generated by this facility should be minimal if all applicable environmental standards are adhered to. The related impacts on tourism should also be minimal.

Spill/Accidental Discharge

A malfunction at an NGL fractionation plant would result in the release of the separated components (i.e., butane, propane etc.) being stored on-site. The magnitude of the environmental effects accompanying any such release would be dependent upon the site-specific conditions and on the volume of the release.

Noise

As with the other natural-gas-related facilities, an NGL fractionation plant involves the use of compressors and boilers. Similarly, the continuous operation of such a facility in a rural site would result in a significant increase in nighttime ambient sound levels. The magnitude of the increase in ambient sound levels would be similar to those noted previously for a gas treatment plant and a gas separation/dehydration facility. In conclusion, the noise effect will be localized and, depending on site-specific conditions, could have an adverse impact on the suitability of the adjacent areas as a location for tourism-related activities.

Aesthetics

The aesthetic impacts of an NGL fractionation facility would be very similar, but somewhat larger than those noted elsewhere for a gas treatment plant. The most visible component of a fractionation plant would be the individual fractionators which can range as high as 150 feet. They would be clearly visible over a significant area due to the flat topography of the study area. The presence of clearly visible fractionators, in coastal locations desired for their aesthetic qualities, would constitute an adverse visual intrusion.

References

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Pervin and Gurtz, Houston, Texas. Personal communication, 1981.

PEAK SHAVING FACILITIES

Facility Description

Peak shaving facilities constitute reserve storage facilities which can supply natural gas to utilities and other consumers during peak demand periods. The obvious advantage of storing natural gas in a liquefied form is that 600 cubic feet of natural gas can be condensed and cooled to occupy one cubic foot in its liquid form. One barrel of LNG is equivalent to approximately 3,450 cubic feet of natural gas.

There are three fundamental steps in the peak shaving process. Natural gas entering the plant is first liquefied by compression and cooling to -260° F. The liquefied natural gas is then stored in specially insulated storage vessels. Finally, the gas is re-vaporized and reinserted into a natural gas transmission and distribution system for distribution to consumers.

A number of storage options exist, but the most commonly used is the conventional above-ground, double-insulated metal tank. These tanks generally have a steel outer wall and an inner wall of aluminum, 9% nickel steel, or austenitic stainless steel. The material of the inner wall must retain its ductility at cryogenic temperatures. In order to contain the contents of the tank in the event of a spill, each tank is surrounded by a diked impounding area with a capacity of at least 100% of the tank capacity. It is generally bottom-lined with moist sand and 2.5 inches of shotcrete to help withstand the thermal shock of a spill.

Facility Size/Land Requirements

Peak shaving plants may contain two or more storage vessels with each having a capacity of up to 900,000 barrels of LNG (equivalent to 3,100 MMcfd of natural gas). They can vaporize up to 116,000 barrels of LNG per day, delivering 400 MMcfd to meet peak demand. The daily delivery capacity (i.e., rate at which gas can be vaporized and delivered to a pipeline) is generally about one-fifth of a peak shaving plant's total storage capacity.

As with other natural gas-related facilities, land requirements for peak shaving plants are indirectly associated with total plant capacity.

The following equation can be used to estimate total land requirements:

$$\text{Land Area} = 94 + .03 + \text{SCP}$$

Where:

Land area = site size in acres

SCP = storage capacity in thousands of barrels of LNG

The facilities would occupy about half the total site while the remainder would be used as a buffer area for safety reasons.

Site Parameters

Peak shaving plants should be located in areas where the soil has good bearing capacity, because of the considerable weight of the liquefied natural gas. Sites should be flat, and situated out of flood plains, areas subject to coastal flooding, and seismically active areas. They should be directly adjacent to an existing gas transmission line. Finally, peak shaving plants should not be located in areas where concentrations of population are adjacent to the site due to the flammability of LNG.

Capital Costs

$$\text{Capital Cost} = (13{,}440{,}000\text{\$/thousands of barrels})\,(1.0017^{\text{SCP}})$$

Where:

SCP = storage capacity in thousands of barrels.

The foundation costs are included in the baseline capital cost equation. This equation assumes the use of a concrete mat foundation over selected backfill.

Sources:
Chicago Bridge and Iron Co., 1982; Ikoku, Natural Gas Engineering, 1980; Public Service Electric and Gas, 1981.

Employment Profile

The construction labor forces for two sizes of peak shaving plants are presented below.

	290,000 Barrel Storage Capacity		580,000 Barrel Storage Capacity	
	Year 1	Year 2 (9 months only)	Year 1	Year 2
Manual	45	58	75	98
Non-manual	5	7	8	12
Total	50	65	83	110

The operating labor force for a peak shaving plant does not vary by size, as these facilities are highly automated and use computerized control systems. The operating labor force for facilities in the size range noted above would consist of 17 persons over a 24-hour shift, 3 non-manual and 14 manual.

Sources:
Bimonte, Joe, July 1982; Transcontinental Gas Pipeline Company, Carlstadt, New Jersey; Wilson, Peter, September 1982, Chicago Bridge and Iron.

Environmental Impact

Air Waste Disposal

During the construction of a peak shaving facility, clearing grading and earthwork activities can generate dust. Dust can be controlled by spraying water on the disturbed areas. With proper dust suppression methods implemented, impacts to air quality and to tourism and recreation are anticipated to be minimal.

Operation of a peak shaving plant will include an occasional vaporization of the gas supply. As a result, nitrogen oxides are emitted in significant amounts. However, because vaporization units are operated approximately 20 days a year, the annual emissions of nitrogen oxides are a relatively insignificant amount. The impacts to air quality and to tourism and recreation are anticipated to be negligible.

Noise

During various phases of facility construction, noise levels will rise and may produce an impact on ambient noise levels. Because of the limited duration of noise and occurrence primarily (if not solely) during daylight hours, construction noise levels are not considered to be a significant impact.

Sources of noise generated during operation are the turbine/compressor set, heat exchangers, and primarily the vaporizer units. Because of the amount of noise generated (113 dB(A) at a reference distance of 3 feet), acoustical treatment is most often a component of the facility's plans. One option includes housing the equipment in an acoustically treated building.

Because of the relatively non-industrial, suburban characteristics of the study area, the increase in ambient noise levels could be a significant impact. An increase in ambient noise levels could be interpreted as a decrease in the quality of an area and could, in turn, affect the number of tourism and recreation participants.

Aesthetic Impact

Large storage tanks may approach 150 feet, thus the aesthetic impacts would be similar to those noted previously for other natural gas-related facilities. In addition, in an effort to maintain safety standards near the facility, trees, bushes and other landscaping are not permitted as a measure to reduce the amount of combustible material near the facility. As a result, the facility's appearance becomes even more blatant.

Accident

LNG is a liquefied flammable gas which is readily vaporized when exposed to external heat sources. The vaporized LNG is not flammable when unconfined (Federal Power Commission, 1976), but is flammable in enclosed areas. A potentially flammable vapor cloud could form if a storage tank were ruptured and LNG escaped into the atmosphere. The probability of an accidental release of LNG due to a storage tank rupture is quite low; conversely, the probability of a release of other flammable liquids, used in either the liquefaction or vaporization processes, is much higher.

The process of liquefying pipeline gas to liquid natural gas will probably entail the use of a mixed refrigerant. The refrigerant consists of hydrocarbons, most likely a mixture of ethane, propane, butane, nitrogen and methane. All of the components except for nitrogen are flammable. A processing accident could leak the refrigerant and result in the potential for a fire or explosion. Methanol, also flammable, may be used during the pretreatment of gas to remove water and carbon dioxide. The potential for fire and/or explosion also exists with the storage and processing of methanol.

Hazard detection, prevention, and mitigation constitute major efforts in the construction and operation of a peak shaving facility. Because of the incorporation of a protective buffer zone around the facility, and siting in low density population areas, danger to the nearby public is reduced.

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TANK FARMS

Facility Description

Petroleum tank farms are used for the storage of crude oil and refined petroleum products. Tank farms store oil arriving from outer continental shelf drilling operations via pipelines, and oil arriving by tanker from overseas producers. When they are located at marine terminals, tank farms store oil offloaded from tankers, or oil sent via overland pipelines awaiting loading onto tankers. Tank farms are also essential components of the oil refining process, storing incoming crude oil prior to its being pumped through an overland pipe to a refinery. Tank farms are also used for storing refined petroleum products prior to their distribution by pipeline, rail, ship, barge, or truck.

Oil storage tank farms may be located at a number of different facilities, depending upon the oil processing and transportation schemes being used. If crude oil is being piped to shore, tank farms may be located near the pipeline landfall, associated with either pumping stations or marine terminals. From either of these facilities the oil is transshipped to refineries in other regions.

Facility Size/Land Requirements

The individual storage tanks can be built to store up to one million barrels each, but storage between 150,000 and 300,000 barrels per tank is more typical. Oil tank farms are also sized on the basis of their throughput capacities. This is the number of barrels per day the facility is capable of pumping from offloading tankers, and it is determined by the capacity of the pipeline supplying the tank farm. Throughput capacities range as high as 1,000,000 barrels/day, with 250,000-500,000 barrels/day being the most common. As a general rule, throughput capacities are generally about one-eightieth of a tank farm's total storage capacity.

The acreage of the tank farm depends on the total storage capacity required and the rate at which incoming oil enters the facility. Tank farms may contain up to 20 storage tanks with total storage capacities approaching five million barrels. The amount of land required for a tank farm depends on its total storage capacity. Approximately 13 to 20 acres are required per one million barrels of oil stored.

Site Parameters

Sites for the tank farm should be flat, not subject to coastal flooding, and have soils capable of bearing the heavy loads associated with storage tanks. If the tank farms are to be used by tankers, the site must also be adequate in terms of wind and wave conditions, and bathymetry. Waterfront locations must be sheltered from adverse weather and wave conditions and the mooring areas must have sufficient depth to accommodate the draft of the largest anticipated tanker expected to utilize the facility.

Capital Costs

As with the land requirements, the costs of a tank farm are dependent upon the total storage capacity of the facility. Capital costs can be estimated using the following equation:

$$\text{Capital Cost} = (18{,}020{,}000\$/10^6\text{barrels})(V) - \$5{,}600{,}000$$

Where:

V = total storage capacity in 10^6 (millions) of barrels

The design assumptions include a reinforced concrete ring foundation on top of a graded and compacted surface with a sand-gravel and asphalt subbase. The tanks are assumed to have fixed-roofs. It should be noted that the above costs are for the oil storage facilities only, and do not include the required unloading/loading facilities. In addition, these costs assume that the storage tanks would be designed, fabricated, and erected at a remote site and delivered to the site by rail, barge, or truck transportation.

Sources:
U.S. Dept. of Interior, Bureau of Land Management, 1979; Oil & Gas Journal, Annual "Pipeline Economics" issues from 1978-80.

Construction Personnel

The number of annual manual and annual non-manual employees required to construct a tank farm with a total storage capacity of 4 million barrels is presented as follows:

Manual	175
Non-manual	25
Total	200

The construction period would last approximately 24 months. Due to economies of scale, additional construction labor force requirements are minimal for facilities with storage capacities greater than 4 million barrels. However, the length of the construction phase would increase.

Following is the number of manual and non-manual employees required to operate a tank farm with a storage capacity of four million barrels:

Manual	27
Non-manual	3
Total	30

The number of employees required to operate tank farms with larger storage capacities would not change due to the highly automated and computerized control systems used in new tank farms.

Sources:
Northern Tier Pipeline Co., Northwest Energy Co., Kitimat Pipeline Ltd., and Trans Mountain Oil Pipeline Corp., Environmental Statement Crude Oil Transportation Systems, Volume 1, 1979; Roy F. Weston Inc., July 1978.

Environmental Impact

Air Waste Disposal

During the construction of tank farms, combustion emissions from heavy machinery operating on-site include nitrogen oxide and carbon monoxide. Dust is also generated by heavy machinery moving topsoil.

Hydrocarbons are the primary emissions from tank farms. Controlling hydrocarbon emissions is important because of their reaction with nitrogen oxides in the presence of sunlight to produce ozone and smog. Sources of hydrocarbon emissions include:

- evaporation from storage tanks,
- evaporation during the transfer of crude oil and fuel, and
- accidental spills and small leaks.

The magnitude of the hydrocarbon air emissions on the ambient air quality is influenced by several of the following factors:

- number of storage tanks
- number of marine vessels (transfer points)
- ambient air conditions
- tank design and tank paint color (colors that increase the reflectivity of light from takes can increase the formation of smog in adjacent areas)

Impacts to tourism and recreation are not anticipated from construction machinery emissions because of New Jersey's Motor Vehicle yearly emission testing to meet specific standards. Impacts to tourism and recreational activities as a result of hydrocarbon emissions will be minimal if emissions are kept to a minimum. If hydrocarbon emissions increase substantially, however, the resultant smog will lessen the quality of the recreation area. Developing ozone is not only harmful to the atmosphere but causes coughing, eye irritation, headache, and damages vegetation. As a result, increased hydrocarbon emissions could make an area undesirable and unsafe, reducing recreation activities.

Solid Waste

Sediment sludges must be removed from the bottom of storage tanks to maintain maximum holding capacity. The sludges are considered hazardous and contain iron rust, iron sulfides, sand, and oil. Disposal in a secured landfill is required.

The impact of tank farm solid waste will be minimal unless the dump site is not properly secured and the sediment sludges are allowed to contaminate the groundwater.

Spill/Accidental Discharge

Because of the large volume of oil stored and transferred at tank farms, oil spills may occur at any time. A spill would have a significant impact on biological resources in the vicinity because of the coating and toxic properties of the oil. A spill might also result in an aesthetic impact if the slick coated recreational beaches or boating areas.

A major oil spill could severely impact tourism and recreation. Fishing, boating, and swimming could conceivably be curtailed as a result of a spill. Clean-up efforts, water current patterns, and site locations all influence the degree of impact of an oil spill on recreation and tourism.

Noise

If the construction of a dock or bulkhead is required, pile drivers will be used. Although they are used only temporarily, they do generate a considerable amount of noise, and ambient sound levels can be expected to increase. During operation, ambient sound levels will rise because of pumps moving oil to and from tanks, pipelines, and tankers.

Increases in ambient sound levels would be noticeable in shorefront recreational areas, and particularly in sparsely-populated rural shorefront areas valued for peace and quiet, thereby possibly affecting recreation and tourism. Higher ambient sound levels would decrease tourists perceptions of a site's suitability as a location for relaxing and escaping the pressures of everyday life. Buffer zones and proximity of the site to recreation areas will determine the extent of the impacts.

Aesthetic Impact

The presence of numerous large tanks, possible round-the-clock operations, and continual lighting would create adverse visual impacts in shorefront recreational areas. In the event of a major oil spill, patches of oil washing up on sandy beaches would have a devastating effect on the visual attractiveness of such areas. In addition, floating oil slicks would adversely affect the visual appearance of water, and result in oil lines on boats and waterfront structures. The presence of oil tanks and the possibilty of adverse aesthetic effects can be mitigated by several factors, including the following:

- buffer zone
- landscaping
- oil spill clean-up measures
- location away from recreation areas

The aesthetic impact of tank farms on recreational and tourism activities can range from a marginal effect to a complete reduction in the area's recreational usage (as in the case of a major spill). Certainly, oil slicks covering sandy beaches will result in swimmers going to other, unaffected beaches. Similarly, recreational boating would decline, and other potential visitors seeking an attractive shorefront location for rest and relaxation would change their patterns of visitation.

Other—Fire Hazard

Tank farms store large volumes of oil and other petrochemicals and, as a result, fires and explosions are ever-present hazards. Even a small fire may produce enough heat to cause explosions of nearby stored oil.

A buffer zone would increase protection for nearby tourists and participants in recreational areas, but would also increase industrial land usage, thereby possibly decreasing recreational areas. An explosion would obviously seriously affect recreation and tourism in the vicinity of the tank farm.

Other--Dredging

If oil is expected to be loaded or unloaded from tankers, construction activities will also include dredging and jetty construction. Dredging will alter the biological resources in the vicinity of the dredged site, due to increases in turbidity, siltation, and the disruption of benthic organisms. If the dredging is extensive, it may change water currents significantly enough to alter the coastline.

Construction and dredging impacts are anticipated to be temporary, and have minimal effect on tourism and recreation. However, a more significant impact will be the use of the coastline for an industrial purpose rather than a recreational purpose.

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NUCLEAR POWER PLANTS

Facility Description

Nuclear power plants generate electricity by capturing the heat from the controlled fission of uranium-235 (U-235), transferring the heat to water, and using the resulting steam to drive turbines that are linked to generators. In the United States, light water reactors are used. Light water refers to the use of ordinary water to cool the reactor core. Heavy water reactors use heavy water, water whose hydrogen atom has an extra neutron, to cool the reactor core.

There are two types of light water reactors--pressurized water reactors (PWRs), and boiling water reactors (BWRs).

A PWR is based on a two-step heat transfer process. Water that circulates around the reactor vessel, contained in a closed high-pressure system called the primary water system, is pumped to a heat exchanger, where its heat is transferred to the secondary water system, producing the stream that drives the generator's turbines. The spent stream is condensed to water by a third water system, often a once-through pass of water from a river, lake, or other source that is consumed by evaporative cooling.

In BWRs, the water that circulates around the reactor core and carries away the heat from U-235 is allowed to vaporize to steam, which directly drives the turbogenerator. Since this water is highly radioactive due to its close association with the fuel module, greater design and operating precautions are necessary against possible leakage of radioactive material. However, a higher thermal efficiency is achieved in this one-step coolant cycle design than in the PWR's two-step cycle.

Facility Size/Land Requirements

Currently operating nuclear power plants have net electric-generating capacities of between 200 megawatts and 1,200 megawatts per unit. Most plants have generating capacities of between 800 and 1,200 megawatts. In many instances two or more generating units are co-located.

Minimum site acreages for nuclear power plants are determined by the Nuclear Regulatory Commission's (NRC's) criteria for determining the exclusion area. The radius of the exclusion area around the plant is determined by the dosage a person would receive in the event of an accidental release of radiation, which in turn is related to plant size.

Exclusion areas are typically .4 mile (NRC, 1979, NUREG 0625). Thus, assuming a half-mile radius around a plant for the exclusion area, and assuming a square site, yields a minimum site size of 650 acres per generating unit.

Site Parameters

Proper siting of a nuclear power plant involves consideration of several factors including:

- o proper topography with adequate flood protection and soils with good load bearing capacity;
- o a seismically inactive region;
- o proximity to electric transmission lines and access to highways;
- o access to and availability of large amounts of water;
- o suitable distance from airport-restricted zones and man-made hazards, and
- o areas of low population density.

The Nuclear Regulatory Commission has very specific regulations concerning population densities permitted within 30 miles of a potential plant site.

Capital Costs

For a plant beginning commercial operation in 1982, the following equation can be used to estimate capital costs:

$$\text{Capital Cost} = \$31{,}840\ (\text{MWe}^{-.4921})\ \text{KWe}$$

Where:

MWe = net electrical generating capacity in megawatts

KWe = net electrical generating capacity in kilowatts

The capital cost of a 1,000 MWe nuclear power plant beginning commercial operation in late 1982 would be:

$$\text{Capital Cost} = (31{,}840\ \$\ 10^3\ \text{watts})(1000^{-.4921} \times 10^6\ \text{watts})(1{,}000{,}000 \times 10^3\ \text{watts})$$

$$= (31{,}840\ \$\ 10^3\ \text{watts})(_{29.94 \times 10^6\ \text{watts}})(1{,}000{,}000 \times 10^3\ \text{watts})$$

$$= \$1{,}063{,}460{,}524$$

These costs are expressed in as-spent dollars. "As spent" dollars are defined as the amount of a revenue or expenditure expressed in the current or nominal dollar amount prevailing at the time the revenue or expenditure was incurred. Thus, the total "as spent" cost of a nuclear power plant beginning commercial operation in 1990 would consist of the sum of the current dollars costs incurred each year throughout the construction period (i.e., 1985 current dollar outlays plus 1986 current dollar outlays, etc.). As an example, assume $1,000 is spent for concrete in 1985, and $1,050 for the same amount of concrete in 1986 (i.e., inflation is 5%/yr.). The total "as spent" cost of concrete during the two-year period would be $2,050.

The equation assumes a location 10 feet above the 100-year flood plain and a concrete mat foundation on bedrock.

Sources:
Budwani, R., Power Engineering, May 1980; Oak Ridge National Laboratory and United Engineers and Constructors, 1980; United Engineers and Constructors, 1977.

Employment Profile:

The labor force required to construct a nuclear power plant is given in table 1.

The manual laborers consist primarily of skilled trades personnel (i.e., boiler-makers, pipefitters, electricians, carpenters, etc.). Non-manual laborers consist of clerical and support personnel (about 20%) and foremen, construction managers and engineers (about 80%).

The operating labor force requirements for the two plant configurations noted in table 1 are indicated as follows:.

	One 1,000 Mwe Unit	Two 1,000 Mwe Units
Manual	40	70
Non-manual	160	285
Total	200	355

Manual workers consist of equipment operators and laborers (i.e., maintenance personnel), while non-manual workers consist of skilled plant operators, engineers, managers, supervisors, and support personnel.

Sources:
EPRI, 1982; Oak Ridge National Laboratory, 1980; Pennsylvania Power & Light, 1978.

Construction and Operating Labor Force Requirements of Nuclear Power Plants

One 1,000 Mwe Unit

Year	1	2	3	4	5	6	7	8	9	10
Manual	52	418	680	1177	1440	2010	1465	628	209	91
Non-manual	13	91	183	243	277	344	328	247	133	47
Total	65	509	863	1420	1717	2354	1783	875	342	138

Two 1050 Mwe Units (constructed concurrently)

Year	1	2	3	4	5	6	7	8	9	10
Manual	100	800	1300	2750	2750	3840	2800	1200	400	175
Non-manual	25	175	350	465	530	659	638	472	256	90
Total	125	975	1650	3215	3280	4499	3438	1672	656	265

Environmental Impact

Air Waste Disposal

Construction machinery required for a nuclear power plant can be anticipated to emit carbon monoxides, nitrogen oxides, sulphur dioxide, and hyrocarbons. Required vehicle emission testing by the State of New Jersey should keep pollutants at a minimum, with minimal tourist impact.

The use of saline water in the mechanical draft cooling towers will most likely result in salt deposition near the facility. Vegetation in the vicinity of the power plant could be adversely affected because of the salt deposition. Impacts to tourism and recreation from air waste disposal are anticipated to be minimal.

Water Use/Water Discharge

Heat from the fission of nuclear fuel in the reactor is used to produce steam at high temperature and pressure, which in turn drives a turbine connected to a generator. The "spent" steam is condensed by passing it through condensers with large amounts of water. The heat is transferred to the cooling water.

Substantial amounts of water are required by the condensers to cool the steam. As a result, organisms small enough to pass through the intake screens and be drawn into the system will be killed. Mortality is due to mechanical, thermal, or chemical shock. Intake screens may impinge fish not large or strong enough to swim safely away. Mortality is anticipated to be 100% for those fish impinged on screens.

Blowdown, the effluent from cooling towers, is discharged continuously, most often at a higher temperature than when originally withdrawn and containing added chemicals. Changes in water temperature may affect reproduction, growth, and survival of larval forms, juveniles, and adults. The warmer water has a lower dissolved oxygen content. Possibility exists for fish and/or plankton kills. Alteration of the aquatic community in the immediate vicinity of the discharge site is anticipated.

Because of state and federal controls on point discharges of liquid wastes, impacts to tourism and recreation should be minimal with proper operations and controls. However, in the event of a large volume of heated waste water being discharged, the water quality and biotic quality will decrease. This may be interpreted as a decrease in the quality of a recreation area and may result in a decline in the number of participants.

Aesthetic Impacts

The most visible components of a nuclear power plant would be natural draft cooling towers (where they are required) and the reactor containment building. Natural draft cooling towers can be as high as 500 feet and would be clearly visible over a sizable viewshed, perhaps as far as 3.5 miles given the flat terrain of the study area. Reactor containment buildings may approach 200 feet in height, and would also be highly visible structures. There would be no way to screen either of these structures through the use of vegetation or intervening structures. Thus, the presence of one or more natural draft cooling towers, or a reactor containment building in scenic coastal locations would adversely affect the aesthetic quality of such areas by introducing a highly visible structure clearly incompatible with the existing visual setting.

Radiological Impacts

The major potential impact associated with a nuclear power plant is the release of radiological liquid and gaseous effluents. Plant design includes shielding of the reactor, hold-up tanks, filters, and demineralizers. Potential releases of radionuclides also exists in the transportation of the nuclear fuel.

Small doses of radiation from the cooling towers and cooling water discharges that are within state and federal limits should pose no threat to wildlife, vegetation, or man. Direct radiation from the machinery within the plant is not expected to be significant at the plant boundary.

A significant effect of building a nuclear power plant is the public's perception of the probability of a malfunction that would release radiation into the surrounding environment. Since Three Mile Island, the public's awareness of the potential or unplanned radioactive release from a facility has certainly been heightened. It is likely that the public's perception of the probability of an unplanned release of radiation is higher than the actual probability of occurrence. Clearly, this heightened perception by the public could act to also significantly decrease their perception of the recreational suitability of an area located in the vicinity of a nuclear power plant.

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COAL-FIRED POWER PLANT

Facility Description

The electricity is produced as steam expands over the length of the turbine, causing it to spin, in turn driving the generator which produces electricity. The combustion of coal requires extensive on-site materials handling capability (i.e., conveyors, stacker/reclaimers, and storage space), and requires the installation of extensive pollution control equipment (i.e., scrubbers and precipitators) to remove the particulates and other pollutants produced during combustion. Coal-fired power plants use large amounts of water to remove the excess heat produced by the combustion of coal (i.e., electric generating plants convert only about one-third of the total heat produced into electricity; the remaining two-thirds is removed by the cooling water).

Coal-fired power plants burn coal in order to produce steam, which is sent through a turbine generator, producing electricity. The major components of a coal-fired power plant include:

Facility Size/Land Requirements

Coal-fired power plants generally range from 100 to 1,000 gross megawatts electrical energy in output capacity per unit. Up to four generating units have been built at a given location. In terms of land use, a large plant (800 megawatts) may require over 1,000 acres of land, mostly for fuel storage and waste disposal. To determine the approximate acreage, output capacity of the plant in megawatts is to be inserted into the following equation:

$$AC = 200 + .5(NEGC)$$

Where:

AC = plant site in acres

NEGC = plant net electrical generating capacity in megawatts

Site Parameters

The site for a coal-fired power plant should be relatively flat, with a good load-bearing capacity soil and a low ground water contamination potential. Cooling water must be available near the site. The site must also be near rail or barge transportation, or both, for fuel delivery. A coal slurry pipeline is another possible fuel delivery option. The plant should also be sited within a reasonable distance of an existing electric transmission line.

Capital Costs

The total capital cost of a coal-fired power plant beginning commercial operation in 1982 can be estimated using the following equation:

$$\text{Capital Cost} = (\text{NEGC}^{-.3538})(\text{NEGCK})$$

Where:

NEGC = net electrical generating capacity in megawatts (10^6watts)
NEGCK = net electrical generating capacity in kilowatts (10^3watts)

The equation yields the following result for a 500 megawatt coal-fired power plant beginning commercial operation in late 1982.

$$\begin{aligned}\text{Capital Cost} &= (\$8451\ 10^3 \text{ watts})(500^{-.3538} \times 10^6 \text{watts})(500{,}000 \times 10^3 \text{ watts}) \\ &= (\$8451\ 10^3 \text{ watts})(.11094 \times 10^{-6} \text{ watts})(500{,}000 \times 10^3 \text{ watts}) \\ &= \$468{,}607{,}950\end{aligned}$$

The total "as spent" cost of a power plant with a 1990 start-up date would consist of the sum of the current dollar costs incurred for each year throughout the construction period (i.e., 1985 current dollar outlays plus 1986 current outlays, etc). "Current," dollars are defined as the amount of a revenue or expenditure expressed in the nominal dollar amount prevailing at the time the revenue or expenditure was incurred. A specified amount of concrete may cost \$100,000 in 1985 and the amount may cost \$110,000 in 1986. The total "as spent" cost for concrete during 1985 and 1986 would be \$210,000.

$$\text{Capital Cost} = \$15{,}072\ (\text{NEGC}^{-.3538})\ \text{NEGCK}$$

Sources:

Oak Ridge National Laboratory and United Engineers and Constructors, Inc., 1980, Power Plant Capital Investment Costs Estimates: Current Trends and Sensitivity to Economic Parameters; Budwani, Ramesh, May 1980, "Power Plant Capital Costs Analysis", Power Engineering.

Employment Profile

Table 1 shows the annual average manpower requirements for a 500 megawatt coal-fired power plant and a 1,000 megawatt facility consisting of twin 500 megawatt units during construction. The figures represent full time, annual workers.

Manual workers include laborers, equipment operators, and skilled trades (i.e., boilermakers, pipefitters, electricians, etc.). Non-manual workers include administrative and managerial workers, secretaries, and engineers.

Sources:

Bechtel Power Corporation, 1982; Budwani, 1982; Burns and Roe, 1978; Electric Power Research Institute, 1982.

The following table shows the operational work force for both of the power plant configurations noted previously.

	One 500 Megawatt Unit	Two 500 Megawatt Units
Non-manual	12	17
Manual	90	123
Total	102	140

Sources:

Burns and Roe, 1978;. Delmarva Power & Light, 1982.

Environmental Impacts

Air Waste Disposal

During construction of a coal-fired power plant, combustion emissions from heavy machinery operating on the site include nitrogen oxide and carbon monoxide. Dust is also generated by heavy machinery moving topsoil. Yearly vehicle emission testing by the State of New Jersey will keep emissions to a minimum.

Emissions from an operating coal-fired power plant will include sulphur oxides, formed as a result of the combustion of the sulfur in coal, and particulates, consisting of silicates, metal salts, and sodium chloride. Also emitted in lesser amounts from coal-fired power plants are nitrogen oxides, hydrocarbons, carbon monoxide, and metallic compounds.

Air quality impacts are influenced by composition of coal (% ash and % sulphur by weight), efficiency of the emission control equipment, and local climatic conditions. The perceived impacts of air waste disposal on tourism and recreation will be negligible with proper environmental controls and compliance with ambient air quality standards.

Water Use/Water Discharge

During construction, sites cleared of vegetation result in exposed topsoil, which decreases the infiltration capacity of the soil. In turn, erosion will increase, producing increased turbidity and siltation in receiving waters.

Operation of a coal-fired power plant involves the use of cooling and process water. The quantity of water used daily creates two problems. Quantity demand may exceed supply during seasonal, low flow periods; and the quantity of water affects biological resources near and around intake pipes and screens, and discharge pipes and structures.

Cooling water discharges can have a thermal impact on receiving waters by raising their temperature and lowering the dissolved oxygen levels. If corrosion-prevention chemicals have been added to the cooling water, the chemicals may affect surface water quality when they are discharged with the cooling water. Surface water may also be adversely affected by the acidic quality of coal-pile runoff. The results of increases in water temperature and declines in water quality include adverse impacts on aquatic ecosystems (i.e., declines in species diversity and productivity of habitats), and decreases in the potability of water.

The impact to drinking water sources and/or aquatic resources as a result of water use and discharge could also impact tourism and recreational activities in the vicinity of the plant. A reduction in the number or type of fish species, or a decline in the productivity of habitats near the site would adversely affect recreational fishing and perhaps boating. Algal growth sometimes associated with a thermal discharge may also cause an aesthetic impact and reduce the use of an area for swimming or recreation boating.

Solid Waste

Operation of a coal-fired power plant results in the production of a considerable amount of solid waste, primarily fly and bottom ash, and scrubber sludge. On-site disposal of these wastes is increasingly becoming the preferred alternative. Large piles of ash and sludge, commonly thirty to forty feet high, would constitute a visual intrusion that is out of character with natural settings of recreational areas. Similarly, the large amounts of land required for disposal would diminish the amount of available land available for recreational uses.

Noise

Ambient sound levels in a non-industrial area can be expected to increase with the construction of a coal-fired power plant. Heavy machinery involved in construction would be the source of increased sound levels.

During operation, ambient sound levels will increase as a result of the operation of coal trains, coal unloading and transfer equipment, and mechanical draft cooling towers.

Because of the non-industrial character of shorefront recreational areas, an increase in ambient sound levels would be a significant impact. Although higher sound levels may not directly decrease the usability of some areas, the subjective perception of a locale's recreational suitability may diminish because it is perceived to be "noisier." The attractiveness of other areas prized for their natural, rural settings as places of relaxation would definitely decline due to an increase in ambient sound levels.

Aesthetic Impact

Although landscaped buffer zones can conceal parts of an energy facility, a coal-fired power plant has three tall and noticeable structures--a stack, a cooling tower, and a coal pile. In the relatively flat, recreational study area these three structures would be visible from a considerable distance. They would be visual intrusions into formerly natural viewsheds.

If the visual and aesthetic impact detracted significantly from the existing aesthetic quality of an area, recreation and tourism activities could diminish as a result of perceptions by users that the suitability or "attractiveness" an area had declined.

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COGENERATION

Facility Description

Cogeneration is broadly defined as a system in which mechanical or electrical energy, and thermal energy are simultaneously produced at one location. The advantage of cogeneration is to utilize what was formerly wasted energy (i.e., hot exhaust gases or hot cooling water) to produce another form of energy. For example, hot exhaust gases can be used to heat steam that in turn is passed through a turbine generator to produce electricity, or hot cooling water can be used for space heating. Given amounts of electricity and thermal energy can be produced for lower fuel inputs than would be required if the same amount of energy were produced in two separate facilities.

Cogeneration configurations in which electricity is first produced, and then the steam or hot cooling water is used for process or space heating, are known as topping cycles. Conversely, a configuration in which thermal energy is first produced (i.e., exhaust gases from an industrial boiler), then used to produce steam that is sent through a turbine generator, is known as a bottoming cycle. Due to the variety of cogeneration configuration, there is no typical application or type of facility. The development of a specific cogeneration application depends upon the energy needs of the primary producer and the needs of the consumer of the cogenerated energy, particularly if the consumer is different than the primary producer. The range of cogeneration applications include the following examples:

- A utility sending hot cooling water from an electric generating plant to a district heating system

- An industrial plant using hot exhaust gases from a smelter to produce steam, then electricity

- A municipal resource and energy recovery facility in which steam is passed through a turbine generator, producing electricity that is sold to the local utility prior to the steam being used in a district heating system

Facility Size/Land Requirements

The size of different cogeneration configurations, in terms of their cogenerated energy outputs, varies widely. The range of the electrical outputs varies from as low as .5-10 megawatts for steam bottoming cycles, up to 5-100 megawatts for steam topping cycles (Detroit Edison, 1980). The thermal output of cogeneration systems ranges from less than 100,000 lbs/hr. of steam to approximately 800,000 lbs./hr. In addition, thermal energy outputs can range from steam at temperatures of up to 1,000^{o}F and pressures of up to 900 pounds per square inch (psi), down to hot water at temperatures of up to 250^{o}F and pressures of up to 200 psi (Detroit Edison, 1980).

Land requirements may range from virtually nothing for a steam bottoming configuration at an existing industrial boiler to site acreages associated with electric-generating facilities and resource and energy recovery facilities which incorporate cogeneration into their designs. Site acreages for these two facilities are given in their facility descriptions.

Site Parameters

Sites for cogeneration facilities should have similar parameters as sites for electric-generating facilities, and resource and energy recovery facilities. Thus, the sites should be flat, with good load-bearing soil, low groundwater contamination potential, and low seasonal water table levels. Sites should be located near surface water bodies in order to obtain cooling water, as well as being located near railroads or large unloading sites for fuel delivery.

In addition, cogeneration facilities have to be located near the consumers of the cogenerated energy. Steam is capable of being sent up to five miles through insulated pipes, while hot water can be sent up to 70 miles (Detroit Edison, 1980). Finally, resource and energy recovery facilities cogenerating electricity must be located near the centers of solid waste generation so as to minimize transportation costs.

Capital Costs

Installed capital costs for various cogeneration cycle configurations range from \$550-\$830/kW of electrical output for bottoming cycles to \$685-830/kW for topping cycles (Power Engineering, 1978). As an example, the installed capital cost of new steam topping cogeneration equipment at the American Cyanamid plant in Bound Brook, New Jersey is estimated at approximately \$780/kW of generating capacity (Argonne National Laboratory, 1980). The capital costs for electric-generating facilities and resource and energy recovery facilities that incorporate cogeneration into their designs would be slightly higher than the capital costs given for these two facilities in their respective descriptions.

The most likely application of cogeneration within the study area is a resource and energy recovery facility that burns municipal solid waste (MSW) in a mass burning unit. This facility produces steam for use in an adjacent district heating system; the steam is first sent through a turbine to cogenerate electricity prior to being extracted from the turbine and sent on to the district heating system. A facility processing 1,800 tons per day of MSW that would produce 370,000 lbs./hr. of steam and generate 30 megawatts of electricity is estimated to have a capital cost of \$119,130,000, while a facility processing 3,000 tons per day that would produce 610,000 lbs./hr. of steam and generate 5 megawatts of electricity would cost \$176,330,000 (Gilbert Commonwealth, 1981).

Sources:
Argonne National Laboratory, March 1980; Detroit Edison, September 1980; Power Engineering, March 1978.

Employment Profile

The labor force required for constructing cogeneration facilities differs widely due to variations in designs and variations in the composition of energy outputs from cogeneration configuration. Electric-generating plants and resource and energy recovery facilities incorporating cogeneration into their designs would have construction labor requirements similar to those presented for the two facilities in their respective descriptions.

Following are construction employment figures for a resource and energy recovery facility that consumes 2,000 tons/day of MSW in cogenerating electricity (from steam) that is eventually sent on to a district heating system.

	Year 1	Year 2	Year 3
Manual	84	350	190
Non-manual	16	50	30
Total	100	400	220

This facility would have a peak employment figure of between 500 and 750 workers occurring during the second year.

The operating labor force for the above facility would consist of approximately 65 manual and 15 non-manual employees spread over two shifts per day, six days a week.

Source:
Mitre Corporation, March 1981, Draft Report: Environmental Impact Statement for a Resource Recovery Facility in Detroit.

Environmental Impact

Air Waste Disposal

During construction, emissions will be generated by the mechanized equipment and vehicles used on-site. These emissions would consist of nitrogen oxide, carbon monoxide, and sulphur dioxide. As with other facilities, New Jersey's yearly vehicle emission testing should keep these emissions at a minimum so that the impacts on recreational and tourist activities would be negligible.

During operation, the air type and quantity of air emissions will be largely determined by the type of fuel used in producing the primary form of energy. Resource and energy recovery facilities that burn municipal solid waste in waterwall incinerators would produce hydrocarbons, hydrochloric and hydroflouric acid, and particulate emissions. Conversely, industrial facilities burning coal in boilers where the hot exhaust gases are used in a steam bottoming application would produce the emissions normally associated with the combustion of coal.

The impact of air waste disposal from cogeneration applications will vary according to the type and size of the energy facility in which the cogeneration occurs. Coal-fired power plants that cogenerate steam for district heating applications would have air waste disposal impacts virtually identical to those for coal-fired power plants that do not cogenerate. Similarly, in industrial applications where the heat from exhaust gases is used to produce steam in a bottoming cycle, there would be no change in the level of air pollutant emissions. In summation, the impact of air waste disposal from cogeneration facilities will correspond with those already described in other sections for the facility that produces the primary form of energy.

Water Use/Water Discharge

Site preparation operations resulting in the clearance of vegetation and the top layer of soil increase the potential for erosion and resulting sedimentation in nearby surface waters. However, if soil erosion and control laws are followed during construction, the temporary impacts on surface water bodies should be minimal.

Substantial quantities of water are required for cogeneration facilities where steam is either used in the production of electricity, or circulated through a district heating system. However, in some instances, the cogeneration of steam for use in district heating systems may actually lessen overall water requirements for a facility by eliminating the need for a condenser or a cooling tower to remove the rejected heat. The volumes of water required will also be largely determined by the type of facility and the type and quantity of primary energy being produced.

The impacts of water use or water discharge from cogeneration facilities on tourism and recreation, as with air emission impacts, will largely parallel those already described elsewhere for the energy facility producing the primary energy output.

Solid Waste

Cogeneration facilities will produce process or combustion residues from the production of the primary energy output. Thus, a resource and energy recovery facility where MSW is burned, and steam is used to cogenerate electricity, would produce process and ash residuals from the combustion of the MSW. The application of cogeneration equipment to an existing primary energy production facility would not generally result in the production of additional amounts of solid waste beyond that already being produced. For example, using steam bottoming cycles to generate electricity in industrial boilers producing hot exhaust gases, the initiation of cogeneration would not result in the additional generation of any solid wastes.

As with the other environmental effects already noted, solid waste production and disposal impacts on tourism and recreational activities associated with a cogeneration facility will be similar to those described elsewhere for the energy facility type producing the primary energy output. Thus, landfilling would be required for the process and combustion residuals produced by a resource and energy recovery facility cogenerating electricity. The result would be the potential to adversely affect groundwater quality through the seepage of leachate from the landfill. The retrofitting of existing industrial boilers to cogenerate energy would result in negligible impacts on tourism, as these facilities are not located in or adjacent to desirable coastal recreation areas.

Noise

The construction of a cogeneration facility would generate significant noise levels from the mechanized equipment use on-site. Sources of sound generation include heavy equipment such as bulldozers, pile drivers, and scrapers. The increase in ambient sound levels from this equipment would be a short term impact, confined to the construction period.

During operation, the size of any increase in ambient sound levels would be a function of the size and type of the energy facility being used to produce the primary energy output. These two factors determine the type of noise-generating equipment that would be present on-site. For example, coal-fired power plants sending steam to a central heating system would include the full complement of equipment such as coal crushers, conveyors, and rail car unloaders needed to handle the coal on-site. In addition, resource and energy recovery facilities that cogenerate energy would result in increases in ambient sound levels in adjacent areas due to the movement of trucks to and from the site.

Without proper mitigating measures, the presence of a cogeneration facility in a recreational area would likely result in an increase in the ambient sound level and a corresponding decrease in the perceived recreational quality of an area.

Aesthetic Impact

Some cogeneration applications would include large structures that would be clearly visible in the coastal areas comprising the study area. Resource and energy recovery facilities would contain a stack up to 300 feet and a main building housing the incinerator and the turbine generator up to 150 feet. Similarly, a coal-fired power plant with cogeneration would contain the highly visible structures already noted previously in the description for that facility. In most instances, the siting of a cogeneration facility in a recreation area prized for its scenic view would constitute a visual intrusion into the landscape that would decrease tourists' perceptions of the recreational suitability of the area.

Odor

Resource and energy recovery facilities would be the cogeneration application with the most significant odor impacts. The storage of MSW prior to combustion can release unpleasant odors to the surrounding arreas if the waste is not properly stored in a closed, sealed enclosure. The presence of such a facility adjacent to a recreational area would certainly result in a decrease in tourists' perceptions of the suitability of the area if odors periodically escaped from the facility.

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RESOURCE AND ENERGY RECOVERY FACILITY

Facility Description

A resource and energy recovery facility is any facility that processes and combusts solid waste and utilizes the thermal energy from combustion for the production of other energy, namely steam and electricity. The technologies used include pyrolysis and the combustion of refuse-derived fuel (RDF) or municipal solid waste (MSW).

Pyrolysis is the thermal decomposition of materials in the absence or near-absence of oxygen. The products of pyrolysis are a gas, a liquid, and a char, all of which can be used for energy production. Pyrolysis is as yet an unproven technology, although it offers promise for the future.

Incineration with heat recovery can be accomplished either by waterwall incineration or by modular incineration, both of which have been used successfully for solid waste disposal. Both processes have the advantage of producing useful energy and using proven technology. The steam generated by these facilities can be used as industrial process steam for heating or for driving electric generators. The facilities may also incorporate the cogeneration of energy, where steam used for district heating or process purposes is first sent through a turbine generator to produce electricity. Two types of fuel are used for incineration, municipal solid waste (MSW) and refuse-derived fuel (RDF).

RDF is produced by processing municipal solid waste (through shredding, magnetic separation, air classification, or other separation techniques) to remove noncombustible materials. The shredded product may be combusted or further processed to form pellets or briquettes.

If a suitable market for the energy produced by a resource and energy recovery facility is not located within economical distance, the RDF produced may be used at other locations to produce steam in a dedicated boiler. The metal and glass by-products can be sold as an additional source of revenue. A number of operational problems associated with mass burning of solid waste can be eliminated by separating out the metal and glass by-products and other non-combustibles prior to combustion.

Facility Size/Land Requirements

Resource and energy recovery facilities have processing and incineration capacities of between 500 and 3,500 tons per day. Most currently operating or proposed facilities range between 1,000 and 2,000 tons per day. Resource and energy recovery facilities may produce up to 40 megawatts of electricity or one million lbs/hr. of steam. However, energy production amounts of 10-15 megawatts or 600,000 pounds per hour of steam are more common.

Resource and energy recovery facilities require 7 to 25 acres of land per facility. The size of the site depends on the capacity and design of the facility and on whether or not the fuel preparation and firing operations are in one location.

Site Parameters

Following are considerations for the establishment of site parameters for a resource and energy recovery facility:

- o flood protection
- o relatively flat land
- o proximity to highway, railroad and/or barge transportation
- o access to electric transmission lines

In addition, resource recovery facilities have locational requirements that affect siting and, in the long run, affect operating and transportation costs. Locational requirements include the following considerations:

- o proximity to sources of waste generation which reflect transportation costs for hauling municipal solid waste,
- o waste composition which influences the amount and type of recoverable material, energy content, types of pollutants, and amount of ash,
- o proximity to markets for recoverable materials (iron, steel, glass, and aluminum), and
- o proximity to a sewage treatment plant for those resource recovery facilities (RRFs) designed to burn sewage sludge.

Capital Costs

Capital Cost = 50,400 (TL) + 28,500,000

Where:

TL = daily combustion capacity in tons.

This is for a resource and energy recovery facility that processes MSW to produce RDF, which is then burned in a waterwall incinerator. The steam produced is sent through a turbine generator to cogenerate electricity prior to being sent off-site for heating or process uses. This cost includes a mechanical draft cooling tower and the necessary air pollution control equipment.

Sources:
Electric Light & Power Magazine, July 1981, Ocean County Solid Waste Management Plan; Union County Solid Waste Management Plan.

Employment Profile

Profiles are for a facility designed to handle 2,000 tons per day of municipal solid waste with a waterwall incinerator.

Construction:	Year 1	Year 2	Year 3
Manual	84	350	190
Non-manual	16	50	30
Total	100	400	220

Peak employment occurs during the second year and averages between 500 and 750.

Operation:	
Manual	63
Non-manual	11
Total	74

Plant is staffed for two shifts per day, five days a week.

Source:
Mitre Corporation, March 1981, Draft: Environmental Impact Statement for a Resource Recovery Facility in the City of Detroit.

Environmental Impact

Air Waste Disposal

During construction of a resource recovery facility, combustion emissions from heavy machinery at the site will include nitrogen oxide, carbon monoxide and sulphur dioxide. New Jersey's yearly vehicle emission testing should keep the pollutants at a minimum.

During operation, emissions will be generated by the facility itself and by the trucks or barges transporting the solid waste. Hydrocarbons, hydrochloric and hydroflouric acid, and particulates will be emitted during the operation of the facility. Emission levels will depend upon the process used to burn MSW or RFD and upon the type of air pollution control equipment used. Air emissions associated with the transfer of solid waste will include nitrogen oxide, carbon monoxide, and sulphur dioxide. Siting parameters and capital costs encourage a central location for hauling trucks to minimize travel time and costs, thereby minimizing vehicle-related air pollution effects. In addition to a central location, New Jersey's emission testing program will aid in limiting exhaust emissions.

The impact of air waste disposal from a resource and energy recovery facility on tourism and recreation is expected to be minimal. Strict New Jersey laws concerning air pollution will keep air quality degradation to a minimum.

Water Use/Water Discharge

During construction, the site is cleared of vegetation and, as a result, the exposed topsoil alters the water retention property of the soil. Erosion and siltation will increase and produce greater turbidity and possible plant growth in nearby surface waters.

Large quantities of water are required for the operation of a resource and energy recovery facility, resulting in the generation of significant amounts of wastewater. Major water requirements include cooling tower makeup (where applicable), steam or hot water production, and boiler makeup. Major sources of wastewater are boiler blowdown, cooling tower blowdown, and ash-handling equipment. Wastewater would probably be pretreated before discharge to a municipal sewer system.

Impacts of water discharges from an RRF on tourism and recreation are anticipated to be minimal. The amount of water used by a resource recovery facility is not likely to lower water supplies.

Solid Waste

Process residue (i.e., waste not included as either RDF or separated out because of its commercial value) and ash residue comprise the majority of solid waste from a resource recovery facility. The non-combustibles and ash must be disposed of in a secure landfill, usually located near the facility.

The solid waste generated by an RRF will have minimal impact on tourism and recreation. However, solid waste disposal by landfilling does have the potential to adversely affect groundwater by leaching, and could impact the number of recreation participants drawn to an area.

Noise

During construction of a resource recovery facility, pile drivers and heavy machinery may generate considerable noise and increase ambient sound levels. This effect would be especially noticeable in a non-industrial area.

Noise from an operating facility will be generated by the acceleration of trucks (delivering MSW) and by several pieces of machinery including:

- shredders,
- conveyors,
- magnetic separators,

- turbine generators, and
- crushers.

Impacts to tourists and recreation participants would be lessened with the incorporation of buffer zones and effective landscaping. However, without these efforts, the perceived quality of an area could decrease and would be expected to adversely affect the number of participants.

Aesthetic Impact

Resource and energy recovery facilities have several large structures that would be easily visible from locations within the relatively flat coastal plain, which constitutes the study area. The building housing the main combustion equipment and turbine generator may be as high as 150 feet, while the stack for some larger facilities may be 300 feet high. Thus, the siting of a large (3,000 ton per day) resource and energy recovery facility in a coastal setting prized for its scenic view would constitute a visual intrusion that detracts from the natural ambience and recreational nature of such locations. The introduction of a visual element clearly out of character with its setting could decrease tourists' perceptions of the suitability of an area as a location for the enjoyment of recreational facilities.

Odor

Accumulated municipal solid waste may create an odor problem prior to burning. This is generally controlled by storing MSW in closed, covered areas with negative draft ventilation (drawing air into the structure) to prevent odor from escaping. In addition, continuous burning at resource recovery facilities ensures that MSW is not stored for any length of time and that combustion is complete.

With proper operation, odors from resource recovery facilities will have minimal impacts on recreation and tourism in the vicinity. Any malfunction in odor control operations would lower the quality and aesthetics of the area, and could conceivably detract from the tourism industry.

Other—Traffic

If the primary method of transporting municipal solid waste is by truck, traffic near the resource recovery area could become congested during peak commuting periods. Siting parameters influence the degree of traffic congestion in and around the site. In most cases, highways and major travel routes will not be affected. Traffic problems will be more evident closer to the facility site. Main routes used by tourists heading to the shore at peak periods (i.e., Friday afternoons) could be temporarily congested due to conflicts with trucks hauling waste to the site.

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ELECTRIC TRANSMISSION LINES

Facility Description

High-voltage electric transmission lines (69 kV and greater) must be installed for bulk transfers of electric power from the power-generating source to the existing electrical transmission system. Transformers at the generating site step up the voltage of the plant-generated electricity to the main transmission voltage.

Economic, technical, and environmental factors determine the size and type of transmission line selected. The line voltage and circuitry needed, length of transmission line, costs, land use, aesthetics, and compatibility with the existing system are factors that affect this decision.

The structural design of electric transmission lines varies greatly. Design variables include structural type and materials, insulation configuration, and number of circuits. Transmission towers may be single-pole wood, single-pole steel, single-pole concrete, wood-pole H-frame, concrete H-frame, or lattice steel. Insulators are configured in horizontal vees, vertical vees, or single string suspension. Single or double circuits can be used. The rationale for using two full-capacity circuits is partly based on having a backup; if there should be a power outage on one circuit, the line could continue to transmit electricity at full output on the other.

Facility Size/Land Requirements

Transmission capacities for electrical lines range from 69 to 765 kV. ROW widths vary from 90 to 280 feet, accordingly. Generally for most tower types, between five and seven towers per mile are required.

Approximately 9 to 42 acres are required per mile of electric transmission line. Land requirements vary with the capacity of the line and the capacity affects ROW width requirements.

Site Parameters

Electric transmission lines are generally routed so as to minimize the disturbance to environmentally sensitive areas, minimize adverse aesthetic impacts (i.e. clear cuts through forests), and minimize cost (i.e., shortest route, lowest ROW clearance and installation costs). In some cases, avoidance of sensitive areas must be balanced with costs where such avoidance would require unusually long corridors. Transmission line corridors passing through regions of high relief, areas having a substantial number of special crossings (i.e., over major highways, rivers, etc.), or heavily wooded or densely populated areas, would result in higher capital costs. Suitable locations for individual towers consist of level areas with soils of sufficient bearing capacity to accommodate the towers, and locations that would be easily accessible for bringing construction materials and power equipment to the site.

Capital Costs

Capital Costs for transmission lines installed above the ground are represented as follows:

169 kV	CC = $162,000 D
230 kV	CC = $285,600 D
345 kV s.c.	CC = $540,000 D
345 kV d.c.	CC = $1,080,000 D
500 kV s.c.	CC = $756,000 D
500 kV d.c.	CC = $1,566,000 D

Capital Costs for transmission lines greater than 230 KV installed below ground are calculated as follows:

Capital Cost = $1,836,000 D

Where:

D = distance in miles

s.c. = single circuit

d.c. = double circuit

These costs assume level topography and minimal special construction costs such as river crossings. In addition, average soil conditions are assumed, which imply concrete mat supports without piles. The cost for underground transmission lines assumes rural/suburban conditions with no pavement-breaking and subsequent recovering. All costs may vary depending on topography, type of ground cover, land use, etc.

Sources:
Burns and Roe, 1980; Electrical World, March 1981; Public Service Electric & Gas, 1981; Rogers and Golden, 1979.

Employment Profile

Construction of an electric transmission line is usually performed in sections along the proposed route, rather than all at once over the entire length of the line. Construction involves two phases--surveying and clearing and tower and line construction.

Individual work crews required during surveying and site clearing range from two to ten workers, with up to ten workers needed in heavily forested areas. A total of up to 40 workers, dispersed among four, five, or more work crews, are generally working on separate locations clearing the ROW along segments of up to 40 miles in length. During construction, up to 60 workers would be dispersed among several work crews over a similarly-sized segment of the transmission line.

Preconstruction crews are expected to move at the rate of ten miles per month. Crews constructing a 138 kV transmission line with single wood towers are anticipated to work at the rate of 10 miles per month. Construction of a 345 kV transmission line with steel towers will take more time, with crews expected to work at a pace of five miles per month. (USDOE, March 1978). Generally, construction work crews can construct between five and ten miles of transmission line per month.

Apart from occasional inspection of lines and maintenance of the right-of-way, no operating personnel are required.

Environmental Impact

Aesthetic Impact

The towers carrying transmission lines vary in size and type. The structures include single wooden poles carrying three wires, and steel lattice structures of up to 150 feet in height carrying up to six conductor cables. The structures may obstruct views for private homeowners in residential areas and may seriously affect the visual quality of natural settings on public lands. The imposition of cleared ROWs in heavily forested areas can constitute a particularly severe aesthetic impact. Selective clearing and vegetative screening can mitigate visual impacts to natural areas, but it is not possible to hide transmission towers entirely.

Impacts on recreation and tourism depend on existing visual quality of the area, topography, and extent of mitigating efforts.

Other--Electrical Effect

Audible noise, communications interference, and ozone production are all caused by "corona" discharges from transmission lines. A corona is an electrical discharge produced when the electric field intensity at a conductor surface exceeds the electric breakdown potential of the surrounding air. The released electrons collide with air molecules to cause the disturbances (Roig, 1979).

Noise due to corona discharges consists of a sizzling sound in wet weather and a barely audible sound in dry weather. Radio interference from corona discharges is evident especially in rainy weather for AM reception near the power line. Interference is usually negligible for FM radio and T.V. reception. Corona discharges from high-voltage power transmission lines produce ozone, similar to the production of ozone during lightening discharges. Because of very small amounts of ozone emitted, it is reasonable to conclude that emission of ozone from transmission lines would not seriously affect air quality.

Because electrical effects are so slight, they are not expected to affect tourism and recreation participants.

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COAL-HANDLING TERMINAL

Facility Description

Coal-handling facilities are involved in the transshipment of coal between water and land modes of transportation. They operate as centers for the export of U.S. coal, and, to a lesser degree, as distribution points for regional utilities and industries. These facilities contain materials handling equipment to move the coal from one transport mode to another, and often have on-site storage capacity.

Coal-handling operations differ in size and on-site facilities, depending on the specific materials-handling system and site of the facility. There are three fundamental approaches to loading coal onto an outgoing collier:

- reclamation of coal entirely from stock,
- loading directly from railcars and/or barges, and
- loading directly from railcars and/or barges as well as reclamation from stock.

Facility Size/Land Requirements

Coal-handling terminals measure capacity or throughput in tons handled per year. In determining land requirements, six acres are required for every million tons per year. Most recently announced plans involve facilities in the range of 10-15 million tons per year, although two million tons per year is a feasible lower limit.

Site Parameters

Siting parameters for a coal-handling terminal include consideration of the following factors:

- flood protection,
- proper topography (relatively flat land with good weight-bearing, capacity soils),
- access to railroads,
- access to an all-weather harbor and adequate wharf or pier,

- suitable amounts of land, and
- groundwater contamination protection.

The volumes associated with specific siting parameters (harbor and acreage) will depend on throughput capacity and draft requirements of ships.

Capital Costs

The equation to determine the approximate cost of constructing a coal-handling terminal is listed as follows:.

Capital Cost = (\$12,000,000)T

Where:

T = the throughput capacity of the terminal in 10^6 tons per year.

This equation assumes foundation costs are included. The foundation design consists of a concrete mat foundation on selected backfill for the onshore loading/unloading equipment. It also includes dredging, and wharf or pier costs. In some locations, expenditures for a large volume of dredging, or high capital costs for a long trestle linking an offshore loading/unloading facility to the mainland, could significantly increase capital costs.

Source:
Alabama State Docks, 1981; Alla-Ohio Coal Co., 1981; Dravo Corp 1981; Port Authority of New York and New Jersey, 1981; Soros Associates, 1981.

Employment Profile

Following are employment profiles for a coal terminal in Virginia, with a 12 million ton per year capacity:

Construction:	Year 1	Year 2
Manual	365	365
Non-manual	37	37
Total	402	402

Manual workers include carpenters, electricians, iron workers, laborers, operating engineers, pipe filters, welders, and pile drivers. Non-manual workers include secretarial and administrative persons, engineers, and project managers. Construction is assumed to be over a 24-month period with the numbers reflecting peak employment at the beginning of the second year.

Operation

Manual	92
Non-manual	4
Total	96

Manual labor will include coal handlers, coal samplers, electricians, quality control inspectors, and maintenance people.

Sources:
A.T. Massey Coal Co., Inc., 1982; Soros Associates, 1981.

Environmental Impacts

Air Waste Disposal

During construction of a coal-handling terminal, combustion emissions from heavy machinery at the site will include nitrogen oxide, carbon monoxide, and sulphur dioxide. New Jersey's yearly vehicle emission testing should keep the pollutants at a minimum.

Operation of a coal-handling terminal involves the transportation of millions of tons of coal. Fugitive coal dust is a major source of air quality degradation. Sources of coal dust include coal handling and coal storage. Coal dust deposited on surrounding areas can:

- o inhibit photosynthesis in plants,
- o harm wildlife that consumes food covered by coal dust,
- o alter soil permeability characteristics,
- o alter the visual quality of the surrounding region, and/or
- o cause respiratory disease.

Means of alleviating sources of coal dust include enclosed systems, dust collection, and water or chemical sprays.

Spontaneous heating and combustion within coal storage areas can create serious environmental and safety problems at transshipment facilities. Spontaneous heating is primarily an oxidation phenomenon involving coal, pyrite, and impure coal substances. Factors affecting spontaneous heating include composition of coal, amount of volatiles in coal, and the method of stockpiling and transportation. Air circulation is the key in preventing spontaneous heating and combustion.

Because the study area has a non-industrial character, air quality degradation in the form of coal dust will be a noticeable impact. Coal dust will affect the quality of recreation and tourist areas and may affect the number of participants. The degree of tourism and recreational impact will depend on the type of coal dust air quality controls.

Water Use/Water Discharge

During construction, the coal terminal site is cleared of vegetation, and, as a result, the exposed topsoil alters the water retention property of the soil. Erosion and siltation will increase and produce greater turbidity and sedimentation in nearby surface waters.

A suitable wharf or pier accessible via a channel of proper depth is required. Dredging will be required to provide sufficient water depth at dockside as well as sufficient channel depth. Dredging will alter the biological resources in the vicinity of the dredged site. If the dredging is extensive, it may change water current patterns significantly enough to alter the coastline.

During operation of a coal-handling terminal, water runoff contaminated by coal and other chemical products can degrade surface and groundwater resources. Pollutants enter the waterways as water reacts with coal pits, dust fallout, and coal spillage. Contaminated runoff contains acids, metals, trace substances, and suspended and dissolved solids. The degree of surface and groundwater impact from coal pile runoff is influenced by the following factors:

- volume of the stored coal
- amount of precipitation
- climate
- terrain and hydrology surrounding the coal pile

Without proper controls, surface and groundwater can be degraded by coal pile runoff, thereby damaging biological resources in the area and lowering the area's aesthetic quality. As a result of poorer water quality, tourists and recreational participants may choose other more usable, aesthetically-pleasing areas for activities such as swimming and fishing.

Noise

Construction activity for a coal-handling terminal includes grading, hauling, and erection of structures. As a result, ambient sound levels can be expected to increase temporarily. During the operation of a coal terminal, the movement of trains and barges to and from the site and the use of coal-handling equipment will increase ambient sound levels. If sound levels rise significantly enough, wildlife in the vicinity of the site may disappear. The aesthetic quality of an area may also decrease with an increased ambient sound level. In an effort to reduce sound levels, control options include enclosing, insulating, shielding, or buffering the site or equipment.

Impacts to tourism and recreation, as a result of the noise generated by coal terminal operation, will be dependent upon the ambient sound levels and the sound control equipment. Because the study area has a relatively non-industrial character, an increase in ambient sound levels will be a noticeable impact on the area thereby possibly degrading the aesthetic quality of an area.

Aesthetic Impact

The major visual quality impact caused by coal-handling terminals results from the obstruction of the horizon. Shiploaders, stacker/reclaimers, the control tower, and the coal stockpile are the tallest structures having the potential to intrude upon the viewsheds of coastal locations. Due to the level topography of the study area, the stockpile and some of the taller equipment could be visible from adjacent areas.

The impact of facility development on visual quality depends on design, type of equipment, and land use. Without the proper siting and design considerations, the aesthetic impact of a coal-handling terminal near a recreation area could lower the quality of an area, thereby reducing the number of participants.

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OFFSHORE OIL PORTS

Description

Offshore oil ports are deepwater ports for unloading crude oil shipments from supertankers (tankers over 175,000 dead weight tons (dwt)) and very large crude carriers (VLCCs). The crude oil is then sent to shore via a pipeline for transportation to other facilities (i.e., tank farm, refinery).

The tankers anchor at unloading buoys called single-point moorings (SPMs). There are several types of SPMs that can be used in transferring crude oil from tankers to pipelines. All include as components an anchored floating buoy, floating hoses for connecting the tanker manifold to the buoy, and undersea hoses connecting the buoy to submarine pipelines. The tanker is attached to the buoy with bow anchor lines and is free to weathervane around the buoy. The oil is transferred through the pipeline to an offshore platform that gathers oil from multiple single-point mooring stations. From here the oil is pumped onshore.

Facility Size/Land Requirements

The recently completed Louisiana Offshore Oil Port (LOOP) has three single point mooring buoys, a 48" pipeline from the offshore pumping station to shore, and an initial unloading capacity of 1.4 million barrels/day. Other proposed offshore oil ports would have similar capacities.

The amount of onshore land required for offshore oil ports depends on the type of support services provided (i.e., pipeline landfall, tank farm, or complete marine terminal). Refer to other energy facility descriptions and their land requirements.

Site Parameters

Factors determining the siting of an offshore oil port include: offshore location for mooring system and pipeline with acceptable wind and wave conditions; bathymetry and marine geology; proximity to onshore storage tanks and oil terminals; and proximity to man-made hazards (i.e. shipping lanes).

Capital Costs

There is no equation for the capital costs of offshore oil ports due to the limited sampling size. The cost of the recently completed Louisiana Offshore Oil Port was approximately $700 million. The Port Authority of New York and New Jersey estimates the cost of a facility transferring 1.4 to 1.5 million barrels per day at approximately $1.2 billion ($\pm$15%) in 1981 dollars. The capital cost varies widely depending upon the quantity of oil transported and the type of onshore storage facilities required.

The total capital cost for a proposed offshore unloading system with a 500,000 barrel per day capacity consisting of two singlepoint mooring buoys, each connected to an onshore tank farm by a 2.5 mile, 48" submarine pipeline is estimated at approximately $62,800,000. This cost includes the undersea pipeline, but does not include any onshore support facilities (United States Department of the Interior, Bureau of Land Management, 1979).

Employment Profile

The employment figures reflect the construction of the Seadock Offshore Oil Port, twenty-six miles off the Texas coast. Seadock consists of two 52-inch crude oil pipelines, an offshore pumping platform, four single point moorings, and an offloading capacity of 2.5 million barrels/day.

Construction:

	Year 1	Year 2	Year 3
Manual (89%)	89	196	178
Non-manual (11%)	11	24	22
Total	100	220	200

Manual workers consist of laborers, equipment operators, and skilled trades workers (i.e., boilermakers, pipefitters, and electricians). Non-manual workers consist of secretarial, managerial, and administrative employees, as well as engineers.

Operation:

Manual (77%)	54
Non-manual (23%)	16
Total	70

The construction employment figures for the 500,000 barrel per day facility noted previously are as follows:

Construction:

	Year 1	Year 2 (8 months)
Manual	135	135
Non-manual	15	15
Total	150	150

Sources:
Roy F. Weston, 1978; U.S. Dept. of the Interior, 1979; and U.S. Department of Transportation, U.S. Coast Guard, 1976.

Environmental Impacts

Offshore oil ports themselves have few environmental impacts (except for a large oil spill). However, associated with offshore oil ports are onshore facilities, including: support bases, tank farms, pipeline landfalls, and marine terminals. The facilities supporting the offshore oil port will have more significant environmental effects that may affect recreation and tourism. These facilities are discussed in accompanying sections and can be reviewed for environmental and associated tourism-related impacts.

Air Waste Disposal

Hydrocarbon emissions can be expected in very small quantities from offshore oil ports during the transfer of oil. Impacts on recreation and tourism as a result of hydrocarbon emissions will be negligible.

Spill/Accidental Discharge

Because of the large amounts of oil being transferred and transported from tankers and through pipelines, the risk of an oil spill is present during operation. Spills can range in size from small operating, accidental spills, to larger more significant spills. Although oil spill clean-up equipment has become more advanced, potential impacts from spilled oil remain. Spilled oil has a detrimental effect on biological resources because of its toxic and coating properties.

The most significant impact of an oil spill to tourism would be the soiling of beaches and recreation areas. If the spill moved onto the coast, the aesthetic degradation would be obvious. In addition, swimming, fishing, and boating activities would be hampered. The impact on recreation and tourism would reflect a significant drop in the number of those industries' participants.

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